BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006 (Filed February 11, 2019)

OPENING COMMENTS OF CALIFORNIA TRANSIT ASSOCIATION TO ORDER INSTITUTING RULEMAKING TO CONTINUE DEVELOPMENT OF RATES AND INFRASTRUCUTRE FOR VEHICLE ELECTRIFICATION AND CLOSING RULEMAKING 13-11-007

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006 (Filed February 11, 2019*)*

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I. Introduction

In accordance with Rule 6.2 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure ("Rules"), the California Transit Association ("Association") submits the following comments on the Order Instituting Rulemaking to Continue Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007.

II. Background

The Association represents more than 250 transit-affiliated entities, including public transit agencies, transit allies/support groups, engineering firms, original equipment manufacturers, and transit industry suppliers. The Association supports advancing zero-emission vehicle ("ZEV") technologies in the public transit industry, and continues to be an enthusiastic partner in the state's efforts to achieve the greenhouse gas ("GHG") emissions reduction and air quality goals of SB 32 (Pavley) [Chapter 249, Statutes of 2016], SB 375 (Steinberg) [Chapter 728, Statutes of 2008], SB 350 (de Leon) [Chapter 537, Statutes of 2015] and various State

Implementation Plan. To that end, the Association has been an active participant in the Commission's work to accelerate widespread transportation electrification, having served as a party to Rulemaking 13-11-007; a respondent to Application 17-01-020 et al.; and, a participant in the Commission's Rate Design Forum, held June 8, 2018, through our rate design consultant, Energy and Environmental Economics ("E3").

As the Commission evaluates the development of new rates and infrastructure for vehicle electrification, the Association urges the Commission to continue to consider the funding constraints of public transit agencies and the unique benefits that electrified public transit can provide to Californian of all socioeconomic backgrounds. Transit bus fleets further the public good by providing clean and energy-efficient mobility options to the general public, including dependent riders and riders in disadvantaged communities, while also facilitating economic activity and the creation of domestic manufacturing jobs. The Association further urges the Commission to consider that the California Air Resources Board's ("CARB") Scoping Plan has identified the transition to an electrified transit bus fleet as a key strategy for meeting the state's 2030 GHG emissions reduction goal.[1] This strategy is now being implemented through the CARB's Innovative Clean Transit regulation ("ICT regulation"), adopted December 14, 2018.

III. Comments

A. Charging Infrastructure Assessment Must Acknowledge the Adoption of the ICT Regulation, Support Its Implementation

With the adoption of the ICT regulation on December 14, 2018, California's public transit agencies became the first heavy-duty fleet owners to be mandated by the state to transition to fully ZEV fleets. The ICT regulation requires transit agencies statewide to begin to purchase zero-emission transit buses ("ZEBs"), beginning in the 2020s, with the goal of transitioning all transit buses in the state to ZEV technologies by 2040. The ICT regulation is identified in the State Implementation Plan and the 2017 Scoping Plan as a necessary component for California to achieve established near- and long-term air quality and climate mitigate targets.

[1] California Air Resources Board, "The 2017 Climate Change Scoping Plan Update: The Proposed Strategy for Achieving California's 2030 Greenhouse Gas Target," p. 34, p. 105

As public transit agencies work to implement the ICT regulation, it is critical that they have access to adequate state funding and/or investments by the investor-owned utilities ("IOUs") to support the buildout of charging infrastructure as well as hydrogen fueling stations necessary to support planned ZEB deployments. The absence of such resources would slow deployment of ZEBs and could even result in modification to the regulation that would make its 2040 goal unattainable.

To support full implementation of the ICT regulation, it is imperative that the Commission work with CARB, the California Energy Commission ("CEC"), and public transit agencies to include the needs of public transit agencies, as dictated by the ICT regulation, as a discernible category in the charging infrastructure assessment. To be useful as a planning tool for the industry and policymakers, this assessment must identify, at the very least: the annual charging infrastructure needs of public transit agencies; estimates of the costs of meeting these annual charging infrastructure needs, based on real world cost data; and, projected funding availability.

B. Consider the Results of the Association-Commissioned Study on Electricity Rate Design in Joint Proposal

Application 17-01-020 et al. resulted in the introduction of Southern California Edison's ("SCE") time-of-use ("TOU") rates for commercial electric vehicle charging and Pacific Gas & Electric's ("PGE") commercial electric vehicle rate. These new rates, which each specifically address demand charges, were introduced in response to concerns raised by a diverse set of stakeholders in the application process about the impact of demand charges on ZEV adoption. While these new rates have not been implemented by SCE or PGE, fleet owners, including transit agencies, have begun to engage with their respective IOUs to better understand their projected benefits. Anecdotal reports from various transit agencies in the Association's membership suggest that these new rates will measurably reduce the cost of electricity as a fuel, cutting at one of the chief barriers to the electrification of our industry. We, therefore, urge the Commission to permit these new rates to advance and recommend that the Commission conduct a robust analysis of their impact on the cost of electricity as a fuel for fleet owners with diverse charging profiles, including public transit agencies. We believe the different rate design characteristics of the new rates introduced by SCE and PGE provide the Commission with an invaluable opportunity to evaluate the strengths of each and call for adjustments, as necessary, that support long-term cost savings to fleet owners relative to today's adopted rates while still adhering to cost-causation principles.

Our support for these new rates notwithstanding, as the Commission continues its efforts to address the common barriers for charging infrastructure deployment related to ZEV charging rates, and compels the submittal of a joint proposal by the IOUs that addresses demand charges in commercial rates, we commend to you the results of a rate design study, commissioned by the Association and conducted by Energy and Environmental Economics ("E3") in 2018. **The rate design study is included as an attachment to these opening comments.**

In this study, E3 developed alternate rate structures to test the impact of various demand and energy charge structures on transit customer bills. To ensure the alternate rate structures are reflective of implementable utility rates, they were constructed using standard utility rate design principles, leveraging 2017 general rate case ("GRC") and 2018 GRC settlement data for PGE and 2018 GRC data for SCE. For customers with monthly loads under 500 kW ("small customers"), E3 designed alternate rates based on PGE's A-10 secondary voltage rate schedule. For customers with monthly loads over 500 kW ("large customers"), E3 designed alternate rates based on SCE's TOU-8 primary voltage rate schedule.

Because this study was intended to recommend the most economic rate structures, the rate level (i.e., the average rate for the customer class, expressed in $/kWh) was not expected to be a driver of results. This assertion was tested and confirmed to be true. For reference, the class average bundled rate used in this study for small customers is approximately 17.6 cents per kilowatt-hour, and the average large customer bundled rate approximately 10.3 cents per kWh, excluding non-bypassable and other charges. These bundled rate levels fall within the ranges of actual 2016 average customer rates for the three California IOUs: for commercial customers average 2016 bundled customer rates ranged from of 13.4 to 19.6 cents per kWh, and 9.3 to 16.2 cents per kWh for industrial customers. Including the default rate designs, 10 rate structures were examined for small customers and 12 for large customers. Because rate designs offered to small customers are typically less complex than those for larger customers, the small customer designs feature TOU energy rates with 3 summer and 3 winter periods and maximum monthly demand charges. The small customer designs do not evaluate time-related demand ("TRD") charges or real-time pricing ("RTP") energy rate structures, however large customer designs do evaluate these charge types. All rate structures developed are revenue neutral to the utilities' relevant revenue requirements, meaning that they collect the full bundled revenue requirement for the relevant customer class. As a result, all rate structures analyzed may be offered as rate options available to public transit accounts.

The study's findings are summarized below.

- With today's battery and charging technology (60 kW electric vehicle service equipment ("EVSE") and 500 kWh battery capacity) and assuming one bus per EVSE:

    - If buses can be 'Smart' charged, the most economic rate structure has maximum monthly demand charges, but higher energy rates in the summer on-peak and winter mid-peak periods and low energy rates outside of these periods. Smart charging can enable agencies to avoid high demand charges and take advantage of low off-peak rates.

    - If Smart charging is not reliably available, the most economic rate structure does not feature a demand charge and has flatter TOU ratios, which reduces the cost of un-managed on-peak charging. Additional benefits can occur under this rate structure if Smart charging is implemented. If from a regulatory perspective it were possible to implement a fully flat rate structure then this would yield the most economic results for today's e-bus technology with un-managed charging.

- Looking to the near- to mid-term future, with 500 kW depot-charging EVSEs and 1,000 kWh bus batteries and assuming one bus per EVSE:

- When charging is un-managed, the most economic rate structure does not feature a demand charge and has flatter TOU ratios. If from a regulatory perspective it were possible to implement a flat rate structure then this would yield the most economic results for unmanaged charging.

- When Smart charging is available for these 'future' buses, the most economic rate structure has time-differentiated demand charges; therefore, if buses can avoid charging in the Summer Peak and Winter Mid-Peak periods, they can avoid incurring a demand charge altogether. Furthermore, because the volumetric component of this rate structure is tied to real-time prices, there is higher volatility in the hourly energy price, which further improves the economics of Smart charging because the lowest-cost hours are notably lower cost than the off-peak hours under a more traditional TOU structure.

- These 'future' buses and EVSEs can provide significant bill reductions if buses are Smart charged. In a scenario with more than one bus charging on an EVSE, 500 kW of charging capacity can provide ten 1,000 kWh buses with the flexibility needed to both avoid incurring time-differentiated demand charges and to take advantage of real-time pricing. The vast majority of this value comes from higher EVSE charging capacity rather than from larger bus battery capacity, though the higher battery capacity allows longer routes to electrify.

Finally, as an organization that believes in a technology-neutral approach to transportation electrification, the Association supports the Commission's direction to the IOUs that the joint proposal address electric rate options for hydrogen fueling stations. We believe strongly that improved economics for the use of hydrogen as a fuel could allow public transit agencies to benefit today from this technology's extended range relative to battery-electric technology.

C. Submetering Vital to Economic Deployment of Zero-Emission Vehicles, Facilitates Tracking of Fuel Costs for ZEVs

Submetering is vital to the economic deployment of ZEVs, including by transit agencies. By allowing utilities and fleet owners to identify ZEV load separate from other customer load, submetering permits fleet owners to track with accuracy the generation of Low Carbon Fuel Standard ("LCFS") credits. LCFS credits, when sold to regulated parties in the program, can significantly offset the higher cost of electricity as fuel for certain entities, including transit agencies, and further incentivize the deployment of ZEVs. Additionally, by allowing fleet owners to identify ZEV load, fleet owners can determine per mile cost of electricity, informing the development of fuel budgets. We encourage the Commission to consider requiring submetering as a component of future infrastructure investments by the IOUs.

IV. Conclusion

The Association thanks the Commission for this opportunity to file these opening comments. We look forward to continuing to engage with you to accelerate widespread transportation electrification, consistent with the goals of SB 350.

Dated: February 11, 2019

Respectfully submitted,

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Rate Design for Electrified Transit

Technical Memorandum

27 July 2018

Energy+Environmental Economics

Rate Design for Electrified Transit

Technical Memorandum

27 July 2018

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1 Executive Summary

A. Project Overview

California has implemented wide ranging climate policies with a goal of reducing greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050. Among these policies is Senate Bill (SB) 350 that, in addition to establishing a 50% renewable portfolio standard (RPS) by 2050, modified Public Utilities Code (PUC) Section 701.1(a)(1) to declare that principal goals of the electric and natural gas utilities' resource planning and investments include "widespread transportation electrification." To support these efforts, the California Air Resources Board (CARB), is expected to implement a zero-emissions purchase requirement for transit fleets.

For buses, trains, and other mass transit vehicles that are fueled with electricity, electric rate structures are a key driver of the transportation electrification (TE) economic proposition. To better understand the impact of rate structures on the economics of electrified transit, the California Transit Association (CTA) engaged Energy and Environmental Economics (E3) to study a range of existing and hypothetical electric rate structures and evaluate them against various representative electrified bus and rail operating profiles.

The term 'rate structure' is used interchangeably with the term 'rate design' throughout this report. A rate structure, or rate design, is comprised of one or more rate components such as customer charge ($ per month), energy charge ($ per kWh), and demand charge ($ per kW-month). Rate structures effectively apportion the utility revenue requirement to each individual customer based on the customer's monthly billing determinants (i.e., energy and demand consumption).

This analysis is not intended to estimate bill impacts for a specific agency, but instead focuses on the general impact of fundamental rate structure forms on transit customer bills, based on a selection of typical transit operating profiles. This analysis is limited to the cost of electricity used to fuel buses and trains; charging infrastructure & other costs associated with electrification of transit operations are outside of the scope of this report.

B. Rate Design Approach

E3 developed alternate rate structures to test the impact of various demand and energy charge structures on transit customer bills.

To ensure the alternate rate structures are reflective of implementable utility rates, they were constructed using standard utility rate design principles, leveraging 2017 general rate case (GRC) and 2018 GRC settlement data for Pacific Gas & Electric (PG&E) and 2018 GRC data for Southern California Edison (SCE). For customers with monthly loads under 500 kW ('small customers'), E3 designed alternate rates based on PG&E's A-10 secondary voltage rate schedule. For customers with monthly loads over 500 kW ('large customers'), E3 designed alternate rates based on SCE's TOU-8 primary voltage rate schedule.

Because this study was intended to recommend the most economic rate structures, the rate level (i.e., the average rate for the customer class, expressed in $/kWh) was not expected to be a driver of results. This assertion was tested and confirmed to be true (see Section 4 for further details). For reference, the class average bundled rate used in this study for small customers is approximately 17.6 cents per kilowatt-hour, and the average large customer bundled rate approximately 10.3 cents per kWh, excluding non-bypassable and other charges. These bundled rate levels fall within the ranges of actual 2016 average customer rates for the three California IOUs: for commercial customers average 2016 bundled customer rates ranged from of 13.4 to 19.6 cents per kWh, and 9.3 to 16.2 cents per kWh for industrial customers.[1]

[1] See https://www.eia.gov/electricity/data/eia861/

Including the default rate designs, 10 rate structures were examined for small customers and 12 for large customers. Because rate designs offered to small customers are typically less complex than those for larger customers, the small customer designs feature time-of-use (TOU) energy rates with 3 summer and 3 winter periods and maximum monthly demand charges. The small customer designs do not evaluate time-related demand (TRD) charges or real-time pricing (RTP) energy rate structures, however large customer designs do evaluate these charge types. Because this analysis may support intervention in electric rate design proceedings, all rate structures developed are revenue neutral to the utilities' relevant revenue requirements, meaning that they collect the full bundled revenue requirement for the relevant customer class. As a result, all rate structures analyzed may be offered as rate options available to public transit accounts. If this approach were implemented, public transit accounts could select the most economic rate option for their usage profile instead of being placed on a potentially less economic default tariff.

C. Charging Profiles

As well as rates, bills for electric buses ('e-buses') also depend on the timing and magnitude of charging. This, in turn, depends on vehicle technology, charger technology, and how each bus operates on a daily basis. We developed a set of 71 Charging Profiles that capture potential differences in these variables for depot-charging e-buses, on-route charging e-buses, and rail. See Section 3 for more details.

To develop Charging Profiles for depot-charging buses, we used data from four of CTA's member agencies for a wide variety of bus routes - not just those currently served by e-buses. We used this data to create 7 'Bus Types' for depot-charging e-buses, each of which represents a common bus use case. The weekday operations of these Bus Types can be summarized as follows:

- A ‘**non-commuter, typical miles**’ bus leaves in the early morning (6:00) and returns late evening (20:00), driving 170 hub miles each weekday;

- A ‘**non-commuter, high miles**’ bus leaves in the earlier morning (4:00) and returns late at night (1:00 the next day), driving 230 hub miles each weekday;

- A ‘**commuter bus, single depot**’ bus leaves and returns to the same depot twice per day, driving 150 hub miles between 6:00 to 9:00 and 14:00 to 18:00 each weekday; and

- A ‘**commuter bus, 2 depots**’ following the same schedule and mileage as the ‘commuter bus, single depot’ scenario above, but spends the hours between driving blocks at a secondary depot.

For each of these, we assumed one Bus Type that operates 5 days a week and one that also runs on the weekend, except we assumed that the ‘non-commuter, typical miles’ Bus Type does not have a 5-day scenario. We also combined each of these Bus Types with a set of Technology and Behavior variables that capture variation in electric vehicle service equipment (EVSE) power and bus battery capacity, modeling:

a) Today’s battery and charging technology (500 kWh battery and 60 kW charging) and

b) A ‘future’ electric bus with a 1,000 kWh battery and 500 kW depot charging. We modeled this ‘future’ bus to ensure that our rate design recommendations were robust to likely upcoming changes in technology.

Finally, we analyzed each combination of these variables under:

a) **Un-managed charging**, which assumes that each bus is plugged into its own EVSE immediately when it arrives to the depot and charged to full as quickly as possible, and

b) **‘Smart’ charging**, which assumes that bus charging can be staggered, delayed and throttled to minimize monthly bills.

For on-route charging, we used an on-route static charging profile that employs hourly 2017 load data from a CTA member agency. The charging profile we used for rail is also based on a static load profile developed from a member agency's actual annual rail usage data for 2017.

D. Summary of Results

Based on our analysis, we draw the following conclusions:

- With today's battery and charging technology (60 kW EVSE and 500 kWh battery capacity) and assuming one bus per EVSE:
    - If buses can be 'Smart' charged, then Small Customer Rate Design #6 (Small #6) is almost always the most economic. This design has maximum monthly demand charges but higher energy rates in the summer on-peak and winter mid-peak periods and low energy rates outside of these periods. Smart charging can produce even bigger bill reductions under this rate than for the Small Customer Rate Design #4 (Small #4), as it can enable agencies to avoid high demand charges and take advantage of low off-peak rates
    - If Smart charging is not reliably available (or costs more than the total bill savings it achieves), then Small #4 is the most economic. This rate structure does not feature a demand charge and has flatter TOU ratios, which reduces the cost of un-managed on-peak charging. Additional benefits can occur under this rate structure if Smart charging is implemented. If from a regulatory perspective it were possible to implement a fully flat rate structure then this would yield the most economic results for today's e-bus technology with un-managed charging.
- Looking to the near- to mid-term future, with 500 kW depot-charging EVSEs and 1,000 kWh bus batteries and assuming one bus per EVSE:

- When charging is un-managed, Large Customer Rate Design #4 (Large #4) is the most economic for nearly all of the Charging Profiles. Similar to the 'current technology' result, this is due to the fact these two rates do not have demand charges. If from a regulatory perspective it were possible to implement a flat rate structure then this would yield the most economic results for unmanaged charging.

- When Smart charging is available for these 'future' buses, the Large #10 rate structure is most economic. This is the result of several factors. First, this rate structure has time-differentiated demand charges; therefore, if buses can avoid charging in the Summer Peak and Winter Mid-Peak periods, they can avoid incurring a demand charge altogether. Furthermore, because the volumetric component of Large #10 is tied to real-time prices, there is higher volatility in the hourly energy price, which further improves the economics of Smart charging because the lowest-cost hours are notably lower cost than the off-peak hours under a more traditional TOU structure.

- These 'future' buses and EVSEs can provide significant bill reductions if buses are Smart charged. In a scenario with more than one bus charging on an EVSE, 500 kW of charging capacity can provide ten 1,000 kWh buses with the flexibility needed to both avoid incurring time-differentiated demand charges *and* to take advantage of real-time pricing. The vast majority of this value comes from higher EVSE charging capacity rather than from larger bus battery capacity, though the higher battery capacity allows longer routes to electrify.

- For on-route charging, the Large #4 design is the most economic. The inflexible on-route charging profile has high maximum monthly demand, often incurred in the late afternoon or early evening. The Large #4 rate design does not include a demand charge, so avoids significant bill impacts from this peaky demand.

- For electrified rail, the variance across the different rate structures is minimal, however the most economic rate is the Large #9 design. This is due primarily to two factors: electric rail's high load factor which reduces the demand charge impact, and the ability of electrified rail to take advantage of spring super-off-peak pricing under the RTP energy rate structure in this design.

- The Peak Day Pricing (PDP) / Critical Peak Pricing (CPP) rate structure is found to add additional economic benefit under Smart charging, however the inverse is also true: if charging is not managed, the PDP/CPP rates are not economic.

- Increased e-bus penetration on a single meter was found to provide an economic benefit when buses are able to Smart charge because the customer charge does not scale with the number of buses. That is, with increased EVSE utilization the customer charge is prorated over additional load, thereby reducing the overall $/kWh cost.

- Other mechanisms such as an economic development rate-style discount, conjunctive billing, and a Southern California Edison Schedule ME-style rate structure could potentially provide additional benefit in certain circumstances.

2 Rate Design Methodology

Utilizing the revenue requirements and billing determinants described in Appendix B, a variety of small and large customer revenue neutral rate structures were designed. At a high level, this process was accomplished by apportioning the class revenue requirement in different ways across customer, demand and energy charges. The process is described in detail in this section of the report. Note that for both small and large customer rate designs, the power factor adjustment is ignored.

Small customers by default are placed on PDP rate structures; large customers by default are placed on CPP rate structures. Under the PDP/CPP rate structure, customers receive a discount on summer time-related demand charges but are charged a high energy charge during PDP/CPP events. PDP/CPP events may occur up to 12 times per year and may last for 4 hours. To align with expected future grid conditions, event periods are assumed to occur between 4 pm and 9pm[2]. Analysis for this study assumes 6 winter and 6 summer CPP/PDP events, with two events occurring on consecutive days and one event occurring separately during each season. For both small and large customers, the PDP/CPP rate structure is evaluated only under the default rate design. Transit charging profiles that are able to respond to the CPP/PDP price signals experience bill savings. Per the terms of these rate schedules, customers may choose to opt out of the PDP/CPP rate structure.

[2] For large customers see Exhibit SCE-01. Phase 2 of 2018 General Rate Case Policy, June 30, 2017. Page 22. For small customers, the PDP is proposed to occur between 5pm and 8pm - see 2017 GRC Phase II Standby and Medium and Large Light and Power Rate Design Supplemental Settlement Agreement Attachment 1. January 31, 2018. Page 10.

A. Rate Designs for Small Customers

Table 1 below provides a summary of the small customer rate designs analyzed. All designs for small customers assume a customer charge of $140 per month, consistent with proposed PG&E A-10 commercial customer rates. Because rate designs for small customers are typically less complex than those for larger customers, the small customer designs feature TOU energy rates with 3 summer and 3 winter periods and maximum monthly demand charges. They do not evaluate time-related demand (TRD) charges or real-time pricing (RTP) structures.

Table 1: Summary of Small Customer Alternate Rate Designs

Small Customer Rate Design Number	1	2	3	4	5	6	7	8	9
Customer Charge ($/month)									
Customer Charge ($/mo)	$ 140.00	$ 140.00	$ 140.00	$ 140.00	$ 140.00	$ 140.00	$ 140.00	$ 140.00	$ 140.00
Distribution Facilities Demand ($/kW-month)									
Summer	$ 11.23	$ 19.91	$ 19.91	$ -	$ -	$ 11.23	$ 9.96	$ 11.23	$ 23.00
Winter	$ 11.23	$ 19.91	$ 19.91	$ -	$ -	$ 11.23	$ 9.96	$ 11.23	$ 18.04
Energy ($/kWh)									
Summer Peak	$ 0.22208	$ 0.18156	$ 0.16645	$ 0.24561	$ 0.30619	$ 0.39012	$ 0.24387	$ 0.20697	$ 0.18156
Summer Mid-Peak	$ 0.16039	$ 0.11987	$ 0.12775	$ 0.20691	$ 0.20215	$ 0.11234	$ 0.16101	$ 0.16827	$ 0.11987
Summer Off-Peak	$ 0.12782	$ 0.08730	$ 0.08994	$ 0.16911	$ 0.14723	$ 0.08182	$ 0.11726	$ 0.13046	$ 0.08730
Winter Mid-Peak	$ 0.14581	$ 0.12351	$ 0.14128	$ 0.20035	$ 0.20144	$ 0.21893	$ 0.16247	$ 0.16358	$ 0.12351
Winter Off-Peak	$ 0.11033	$ 0.08803	$ 0.08127	$ 0.14034	$ 0.14357	$ 0.08387	$ 0.11580	$ 0.10357	$ 0.08803
Spring Super Off Peak	$ 0.07399	$ 0.05169	$ 0.04772	$ 0.10679	$ 0.08430	$ 0.04925	$ 0.06800	$ 0.07002	$ 0.05169
CPP									
Event Charge ($/kWh)	$ 0.90	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Event Credit ($/kW-mo, summer)	$ (3.61)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

A brief description of each small customer rate structure is provided below.

2.1.1 SMALL #1: DEFAULT DESIGN

PG&E's A-10 rate, the default rate design, collects distribution costs via both seasonal energy rates and maximum demand charges. Distribution costs collected in energy rates vary by season but not by TOU; generation costs are collected in energy rates that vary by TOU. Small Design 1 was analyzed both with and without PDP charges.

2.1.2 SMALL #2: FULL DEMAND CHARGE

The Small #2 rate structure collects all transmission and distribution costs via a demand charge and collects generation costs per the default A-10 TOU energy ratios.

2.1.3 SMALL #3: FULL DEMAND CHARGE + FLATTER TOU ENERGY

The Small #3 rate structure is similar to Small #2 in that it collects all transmission and distribution costs via a maximum monthly demand charge. However, Small #3 collects generation costs per energy rates employing marginal cost TOU ratios rather than the A-10 energy TOU ratios.

2.1.4 SMALL #4: NO DEMAND CHARGE + FLATTER TOU ENERGY

Rate design Small #4 collects all transmission and distribution costs via seasonal energy rates and collects generation costs per energy rates with marginal cost-based TOU ratios.

2.1.5 SMALL #5: NO DEMAND CHARGE

The Small #5 rate structure collects generation, transmission and distribution costs via energy rates with the default A-10 energy TOU ratios. This rate structure is similar to SCE's EV-8 rate for the first 5 years.

2.1.6 SMALL #6: DEFAULT DEMAND CHARGE + HIGH ON-PEAK ENERGY

Small # 6 is identical to Small #1, except it collects the share of distribution costs collected in energy rates in the summer on-peak and winter mid-peak periods only.

2.1.7 SMALL #7: LOWER DEMAND CHARGE + HIGH ON-PEAK ENERGY

The Small #7 rate structure collects fifty percent of the transmission and distribution costs via a demand charge and the remaining fifty percent via energy rates employing the default TOU energy ratio instead of via seasonal energy charges. This rate structure is similar to SCE's EV-8 rate from year 11.

2.1.8 SMALL #8: DEFAULT DESIGN WITH FLATTER TOU ENERGY

Rate design Small #8 is the default A-10 design (Small #1) except that generation costs are collected via energy rates with a marginal cost TOU ratio.

2.1.9 SMALL #9: FULL SEASONAL DEMAND CHARGE

The Small #9 rate structure is similar to Small #3 with all distribution and transmission costs collected via a demand charge, except that demand charges are seasonally differentiated rather than flat. The chart depicts the summer period demand; the winter level is $18.04.

B. Rate Designs for Large Customers

Table 2 below summarizes the large customer rate designs analyzed. All designs for large customers assume a customer charge of $219.55 per month, consistent with proposed SCE TOU-8 primary voltage commercial customer rates. The large customer rate designs examine TOU and RTP energy rates, maximum monthly demand and TRD charges.

Table 2: Summary of Large Customer Alternate Rate Designs

Large Customer Rate Design Number	1	2	3	4	5	6	7	8	9	10	11	12
Customer Charge ($/month)												
Customer Charge ($/mo)	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55	$ 219.55
Distribution Facilities Demand ($/kW-month)												
Summer	$ 14.08	$ 14.08	$ 18.44	$ -	$ -	$ 12.45	$ -	$ 9.39	$ 14.08	$ -	$ -	$ 9.39
Winter	$ 14.08	$ 14.08	$ 18.44	$ -	$ -	$ 12.45	$ -	$ 9.39	$ 14.08	$ -	$ -	$ 9.39
Energy ($/kWh)												
Summer Peak	$ 0.08762	$ 0.08762	$ 0.28974	$ 0.20598	$ 0.06445	$ 0.33018	$ 0.19466	$ 0.17257	$ 0.08762	$ 0.06445	$ 0.10874	$ 0.08798
Summer Mid-Peak	$ 0.08157	$ 0.08157	$ 0.04995	$ 0.18506	$ 0.05791	$ 0.10375	$ 0.18355	$ 0.16147	$ 0.08157	$ 0.05791	$ 0.10969	$ 0.08893
Summer Off-Peak	$ 0.04146	$ 0.04146	$ 0.04023	$ 0.12113	$ 0.03790	$ 0.04513	$ 0.10638	$ 0.08429	$ 0.04146	$ 0.03790	$ 0.06949	$ 0.04872
Winter Mid-Peak	$ 0.07185	$ 0.07185	$ 0.09192	$ 0.10771	$ 0.04918	$ 0.13612	$ 0.13612	$ 0.11381	$ 0.07185	$ 0.04918	$ 0.08596	$ 0.06296
Winter Off-Peak	$ 0.04489	$ 0.04489	$ 0.04131	$ 0.09048	$ 0.04131	$ 0.05050	$ 0.08813	$ 0.06583	$ 0.04489	$ 0.04131	$ 0.04771	$ 0.02472
Spring Super Off Peak	$ 0.02712	$ 0.02712	$ 0.02628	$ 0.05756	$ 0.02628	$ 0.02973	$ 0.06397	$ 0.04167	$ 0.02712	$ 0.02628	$ 0.04235	$ 0.01934
Time-related Demand ($/kW-mo)												
Summer - Peak	$ 21.24	$ 21.24	$ -	$ -	$ 44.57	$ -	$ -	$ -	$ 21.24	$ 75.69	$ -	$ -
Summer - Mid-peak	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Winter-Mid-peak	$ 4.17	$ 4.17	$ -	$ -	$ 20.83	$ -	$ -	$ -	$ 4.17	$ 4.17	$ -	$ -
CPP												
Event Charge ($/kWh)	$ 1.34519	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Event Credit ($/kW-mo, summer peak)	$ (11.82)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

A brief description of each large customer rate structure is provided below.

2.1.10 LARGE #1: DEFAULT DESIGN WITH CPP

The Large #1 rate design is SCE's TOU-8-CPP rate, the default rate design. It collects distribution costs via a combination of TOU energy rates, TRD charges and maximum demand charges. Transmission costs are collected via maximum monthly demand charges. Energy costs are collected via TOU energy and TRD charges. This rate structure additionally employs CPP pricing.

2.1.11 LARGE #2: DEFAULT DESIGN WITHOUT CPP

The Large #2 rate structure is similar to Large #1 except it does not employ CPP pricing.

2.1.12 LARGE #3: NO TRD, ENERGY VIA MC TOU RATIO

Rate design Large #3 collects all transmission and distribution costs via maximum monthly demand charges. Generation capacity is collected in summer on-peak and winter mid-peak energy charges. Energy charges utilize marginal cost (MC)-based TOU ratios. No TRD charges are utilized in this rate design.

2.1.13 LARGE #4: NO DEMAND CHARGES

Rate structure Large #4 collects all costs except the customer charge via energy charges utilizing the proposed default TOU ratio.

2.1.14 LARGE #5: ALL DEMAND PER TRD + TOU ENERGY

The Large #5 design collects transmission and distribution costs via TRD charges in the summer on-peak and winter mid-peak periods. Generation capacity costs are also collected via TRD charges. Energy charges utilize the proposed default TOU ratio.

2.1.15 LARGE #6: CURRENT EV-6 RATE

Large #6 is the current SCE EV-6 rate structure. It does not feature a TRD charge. Compared to the default design (Large #1) it collects a smaller portion of distribution costs in maximum monthly demand charges and remaining costs in TOU energy charges.

2.1.16 LARGE #7: NEAR-TERM PROPOSED EV-9

Rate structure Large #7 is the proposed near-term SCE EV-9 rate structure. For the introductory five-year period this rate structure is offered, SCE proposes that this rate be structured to recover all generation- and distribution-related costs through seasonal TOU Energy Charges on a cents-per-kWh basis, and transmission costs through non-seasonal and non-TOU energy charges. Therefore, this design collects all costs except the customer charge via energy charges. This design is similar to Large #4 but with different TOU ratios.

2.1.17 LARGE #8: LONG-RUN PROPOSED EV-9

Rate design Large #8 is the proposed long-run SCE EV-9 rate structure that SCE proposes will be collected from year 11 from its introduction. This design collects 40% of distribution costs in TOU energy rates, and all transmission costs and remaining distribution costs in maximum monthly demand charges. No costs are collected in TRD charges.

2.1.18 LARGE #9: LARGE #2 WITH RTP

The Large #9 design is identical to Large #2 except instead of TOU energy charges the energy rates feature an hourly RTP structure.

2.1.19 LARGE #10: DEMAND PER TRD + ENERGY PER RTP

The Large #10 design collects generation capacity, transmission and distribution costs via summer on-peak and winter mid-peak TRD charges. Energy costs are collected via an hourly RTP structure.

2.1.20 LARGE #11: PROPOSED NEAR-TERM EV RATE WITH RTP

Large #11 is the proposed near-term EV rate (Large #7) with RTP energy pricing instead of a TOU energy structure.

2.1.21 LARGE #12: PROPOSED LONG-RUN EV RATE WITH RTP

Design Large #12 is the proposed long-run EV rate (Large #8) with RTP instead of TOU energy rates.

3 Charging Profile Methodology

The electricity bills generated by "e-buses" and trains depend on both a) the electric rate structure and b) the timing and magnitude of charging. The latter depends on electric vehicle technology, charger technology, and how each electric vehicle operates on a daily basis (including miles driven, driver behavior, willingness and ability to "Smart" charge, and the location of charging). In this study, Smart charging is defined as bus(es) on a single EVSE a) delaying charging, b) sequencing charging, and/or b) charging at a power level below the maximum capacity of the EVSE in order to minimize monthly electric bills. A set of Charging Profiles that captures potential differences in these variables was developed for depot-charging "e-buses", on-route charging e-buses, and rail. A total of 71 Charging Profiles were developed covering depot and on-route e-bus charging, as well as an electrified rail scenario.

A. Charging Profiles for Depot-Charging e-buses

Bus block data was collected from CTA's member agencies for a wide variety of bus routes - not just those currently served by e-buses. We requested this data from 15 agencies and received data on 2,238 bus blocks from 4 agencies. We used this data to create 7 'Bus Types' for depot-charging e-buses, each of which represents a common bus use case.

The weekday operations of these Bus Types can be summarized as follows:

- A 'non-commuter, typical miles' bus leaves in the early morning (6:00) and returns late evening (20:00), driving 170 hub miles each weekday;

- A 'non-commuter, high miles' bus leaves in the earlier morning (4:00) and returns late at night (1:00 the next day), driving 230 hub miles each weekday;

- A ‘commuter bus, single depot’ bus leaves and returns to the same depot twice per day, driving 150 hub miles between 6:00 to 9:00 and 14:00 to 18:00 each weekday; and

- A ‘commuter bus, 2 depots’ following the same schedule as the ‘commuter bus, single depot’ above and driving the same miles, but spending the hours between driving blocks at a secondary depot.

We ran two Bus Types for each of these four weekday operations: one that operates 5 days a week, and one that also runs on the weekend. All 7 resulting Bus Types are shown in Table 3.

Table 3: Summary of Bus Types

		Weekday operations (24-hour time)					
	Bus Type	Depot leave time 1	Depot return time 1	Depot leave time 2	Depot return time 2	Daily hub miles	Weekend operations
1	Non-commuter, typical miles, 7 days	6:00	20:00	NA	NA	170	Same as weekday schedule for ‘Non-commuter, typical miles, 7 days’
2	Non-commuter, high miles, 7 days	4:00	1:00 next day	NA	NA	230	Same as weekday schedule for ‘Non-commuter, typical miles, 7 days’
3	Non-commuter, high miles, 5 days	same	same	same	same	same	Does not operate on weekends
4	Commuter bus, single depot, 7 days	6:00	9:00	14:00	18:00	150	Same as weekday schedule for ‘Non-commuter, typical miles, 7 days’
5	Commuter bus, single depot, 5 days	same	same	same	same	same	Does not operate on weekends
6	Commuter bus, 2 depots, 7 days	6:00	9:00	14:00	18:00	150	Same as weekday schedule for ‘Non-commuter, typical miles, 7 days’
7	Commuter bus, 2 depots, 5 days	same	same	same	same	same	Does not operate on weekends

Each of these Bus Types was combined with a set of Technology and Behavior variables that capture variation in charging behavior, electric vehicle service equipment (EVSE) power, bus battery capacity, and the number of buses scheduled to charge each day on the power provided by a single EVSE. These are described in Table 4 below.

Table 4: Technology and Behavior Variables used to define Charging Profiles

Charging behavior assumption	EVSE Power	Buses Served by EVSE Power	Bus battery capacity
Un-managed charging	60 kW	EVSE power serves 1 bus	500 kWh**
			1,000 kWh
	500 kW	EVSE power serves 1 bus	500 kWh
			1,000 kWh
Smart charging	60 kW	EVSE power serves 1 bus	500 kWh
			1,000 kWh
		EVSE power serves 3 buses, where feasible	500 kWh
			1,000 kWh
	500 kW	EVSE power serves 1 bus	500 kWh
			1,000 kWh
		EVSE power serves 3 buses	500 kWh
			1,000 kWh
		EVSE power serves 10 buses, where feasible	500 kWh
			1,000 kWh

- 4 e-buses could be served by 60 kW EVSE power in only 2 cases: commuter buses with 2 depots and 1,000 kWh batteries. A small number of cases showed 3 e-buses able to charge using 60 kW EVSE power at each depot. In many cases, only 1 or 2 buses could sufficiently charge with 60 kW EVSE power at each depot.

** Note that Bus Types 3 and 4, the "High Miles" buses, drive 230 miles per day and were therefore not able to be served with a 500 kWh battery. They were only analyzed with a 1,000 kWh battery.

Additional detail on these variables is provided below.

- **Charging Behavior** was assumed to be either:
    - **Un-managed**, in which case an e-bus begins charging as soon as it arrives at a depot and continues charging until full, or
    - **Smart**, in which case the bus(es) charging using the power a single EVSE can minimize monthly electric bills by a) delaying their charging, and/or b) charging at a power level below the maximum capacity of the EVSE. These Smart charging functions are available with today's technology. In addition, if there is more than one bus using the power of a single EVSE (see the third column of Table 4), then our Smart charging profiles assume that all buses can be charged simultaneously. Technology provider The Mobility House provides a smart charging solution that enables real-world implementation of this modeling assumption. Another company, Cyber Switching, also provides a similar ability. Appendix A provides more detail on our Smart charging methodology.
- **EVSE Power** assumes either
    - A 60 kW case to reflect typical overnight-charging conditions today, or
    - A 500 kW case intended to capture a high-powered charging design (for reference, 500 kW is currently typical of EVSE used for on-route charging).

  For the two-depot commuter Bus Types, , we assume that the same EVSE Power is available at each of the two depots. These buses are assumed to move between the two depots over the course of a day and are therefore billed two customer charges and, to the extent that electricity demand is incurred at both sites, two demand charges, if applicable under the relevant alternate rate structure.

- **Buses Served by EVSE Power.** All 'Un-managed' charging cases assume one bus per EVSE at each depot. Smart charging cases are run assuming
    - One bus,
    - Three buses, or
    - Ten buses are served by the available EVSE Power.

  This assumption is intended to help agencies assess the value of additional charging power.

  We also ran some boundary cases with *two* buses per EVSE and *more than* ten buses per EVSE, before arriving at our 1, 3 and 10 assumptions.

- **Bus Battery Capacity** assumes either
    - 500 kWh, intended to reflect a current, typical new e-bus. Two transit agencies indicated that they have recently purchased 40-foot buses with 440 kWh and 480 kWh capacities. BYD's current best-in-class 40-foot bus is 500 kWh,[3] New Flyer runs up to 545 kWh,[4] and Proterra's is 660 kWh,[5] or
    - 1,000 kWh, intended to capture a short- to mid-range future design.

  We assumed a 30% minimum state of charge (SOC). That is, e-buses with a 500 kWh bus battery were not permitted in our modeling to fall below 150 kWh SOC at any time, and the 1,000 kWh battery was not permitted to fall below 300 kWh. This minimum SOC was

[3] http://en.byd.com/usa/wp-content/uploads/2018/04/k9mc.pdf
[4] https://www.newflyer.com/site-content/uploads/2018/03/HowItWorks-Charging-Solutions-web.pdf
[5] https://www.proterra.com/products/catalyst-40ftold/

implemented to account for agencies' operational (range) buffer, ongoing battery degradation, and static losses.

We also assumed that e-buses consume 2 kWh per mile (i.e. they are able to drive 0.5 miles per kWh), based on a review of transit agency data and CTE modeling, as presented in Table 5. Transit Agencies #1 and #2 denote two actual California transit agencies that provided data for this study.

Table 5: Data sources for kWh per mile traveled by electric buses

Source	kWh consumed per mile	Notes
Transit agency #1 fleet average:	2.47	First bus purchased in 2012
Foothill transit case study 10-year average: [6]	2.15	Fairly constant (2004 – 2015)
Transit agency #2 fleet average:	1.85	In service early 2017, flat route
CTE modeling of typical routes:[7]	1.69 - 3.10	

Two kWh per mile was selected as a round, representative mid-point among these data points, and does not account for potential future increases in battery efficiency. Since this value is highly variable across agencies, routes and operating conditions, we further investigated the impact of this assumption. If the battery were less efficient (i.e. buses required increased kWh per mile), then the bus battery would require more electricity for a given route and would therefore require more time to re-charge. The impact of this change on electricity bills in our modeling would be similar to the impact of a longer route: more electricity and more time would be required during each charging session. This would increase the total *bill* but would not change our *rate structure*

[6] National Renewable Energy Laboratory, January 2016, "Foothill Transit Battery Electric Bus Demonstration Results," https://www.afdc.energy.gov/uploads/publication/foothill_transit_beb_demo_results.pdf
[7] Erik Bigelow, Center for Transportation and the Environment, 2017, "Battery-Electric Buses 101," *Presentation at APTA Sustainability and Multimodal Planning Workshop,* http://www.apta.com/mc/sustainability/previous/2017sustainability/presentations/Presentations/Battery-Electric%20Buses%20101%20-%20Erik%20Bigelow.pdf

recommendation. As discussed in Section 4, the key consideration for rate structure recommendation is whether charging is Smart or unmanaged.

Finally, we applied an additional 10% loss factor. That is, the charger-to-battery charging efficiency of each e-bus battery (kWh consumed / kWh billed) was assumed to be 90%. This is based on Foothill Transit's e-bus demonstration results.[8] This means that we model 2.22 kWh *billed* per mile.

Combining these Technology and Behavior Variables with the Bus Types described above resulted in a total of 66 "Charging Profiles" for depot-charging e-buses.

Each Charging Profile was analyzed using all eligible rate structure alternatives as defined in Section 2. The 60 kW EVSE Charging Profiles were analyzed using the Small Customer rate designs, and the 500 kW EVSE Charging Profiles were analyzed using the Large Customer rate designs. Our analysis assumes that e-bus charging is separately metered from any adjoined facility load.

Section 3 B below discusses the on-route Charging Profile that was analyzed in addition to depot-charging e-buses. Section 3 C discusses the charging profile for rail.

B. Charging Profile for On-route *Charging* e-buses

The on-route charging profile employs hourly 2017 load data from a CTA member agency that was able to provide a static load profile for two 500 kW chargers serving 14 buses, each with 72 kWh battery capacity. The buses each charge for five to seven minutes every hour. Given the high peak demand typical of on-route charging and observed in this static load profile, we analyzed on-route charging using the large customer rate structures.

C. Charging Profile for Rail

The charging profile we used for rail is a static load profile developed from a member agency's actual annual rail usage data for 2017. Given the high peak demand observed in the rail static load profile, the large customer rate structures are analyzed under this Charging Profile. Note that the rail scenario assumes conjunctive billing treatment, such that the maximum demand coincident on the rail system is billed monthly rather than per the non-coincident maximum demand at each traction power injection point.

4 Results

Multiplying annual usage for each Charging Profile by relevant small or large customer rates yields a range of annual electricity bills for each Charging Profile. Annual electricity bills are divided by annual usage (kWh) for each Charging Profile to produce an average rate metric ($/kWh) that can be compared for small or large customers across Charging Profile scenarios.

The following additional assumptions were made:

- Our bill analysis was performed for a single year. Market energy prices for small customers reflect a 2020 penetration of renewable energy resources, and for large customers a 2021 penetration of renewable energy resources. This assumption is consistent with the PG&E and SCE GRC data utilized in this study.

- We do not include in our bill analysis any additional facility loads. Significant electricity demand from an adjoined facility metered on the same account as e-buses could produce findings that are different from our analyses.

- In calculating bills, we do not include any revenues that may be available to transit agencies from vehicle-to-grid (V2G) services or other utility programs (e.g. demand response).

Findings described below. The findings are organized to answer the following key questions:

a. Which rate structure is best for today's e-buses under smart and un-managed charging? What bill savings are available from Smart charging?

b. Which rate structure is best for tomorrow's e-buses under Smart and un-managed charging? What are the bill savings from Smart charging?

c. What is the relative impact of larger battery capacity versus larger EVSE capacity on the value of Smart charging?

d. Does rate level impact these rate structure recommendations?

e. What is the impact of the CPP / PDP rate structure?

f. What is the impact of increased EVSE utilization?

g. How constrained are the high EVSE utilization cases?

h. Are there additional discount mechanisms that CTA could pursue?

A. Which Rate Structure is Best for *Today's* Depot-charging E-Buses Under Unmanaged and Smart Charging?

Results presented in this section assume a single bus on a single EVSE.

4.1.1 UN-MANAGED DEPOT-CHARGING BUSES

Figure 1 below displays the average annual bill ($/kWh) for today's typical e-buses: a 500 kWh battery (effectively 350 kWh of storage, given the assumed 30% minimum state of charge), with a 60 kW EVSE. These buses are analyzed using small customer rates. This analysis assumes un-managed charging and was run for three different Bus Types: a Non-Commuter, Typical miles; a one-depot commuter bus; and a two-depot commuter bus. A fourth Bus Type, the Non-Commuter, High Miles bus, was also to be included, but a 500kWh battery was too small to enable 230 miles and keep a 30% minimum SOC.

As is evident in the figure, there is a wide spread in average annual bill results cost across the range of rate designs. The order of preference, however, is consistent: the Small #4 design is the most economic in all cases, and Small #5 is a close second. Small designs #4 and #5 are the two small customer rate structures that do not include a demand charge. This result occurs because under un-managed charging, charging is done as quickly as possible and as soon as buses return to their charging facilities. This means that the maximum demand is incurred for just a few hours of the day, causing significant bill impacts under rate designs that have a demand charge. Small #4 has flatter TOU ratios, meaning a smaller difference between the on-peak TOU price and the off-peak (or super off-peak) price than Small #5, which reduces the cost of unmanaged on-peak charging. A fully flat rate structure would in fact yield the most economic results for this scenario; the corresponding flat rate would be $0.20 per kWh which is lower cost than all of the alternate rate structure results presented here.

Figure 1: $/kWh bill for e-bus with 500 kWh battery, 60 kW EVSE, by rate design, assuming un-managed charging

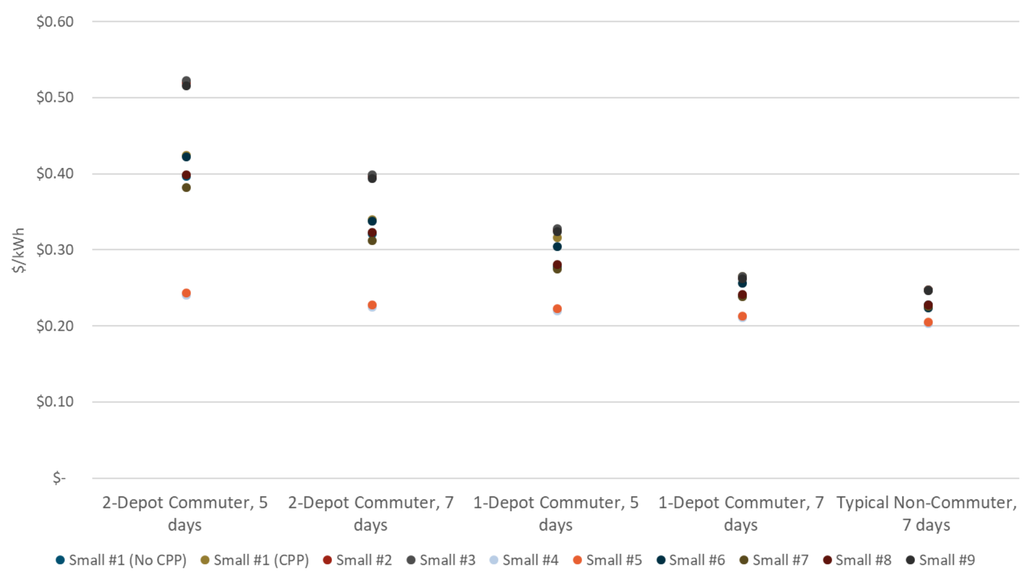
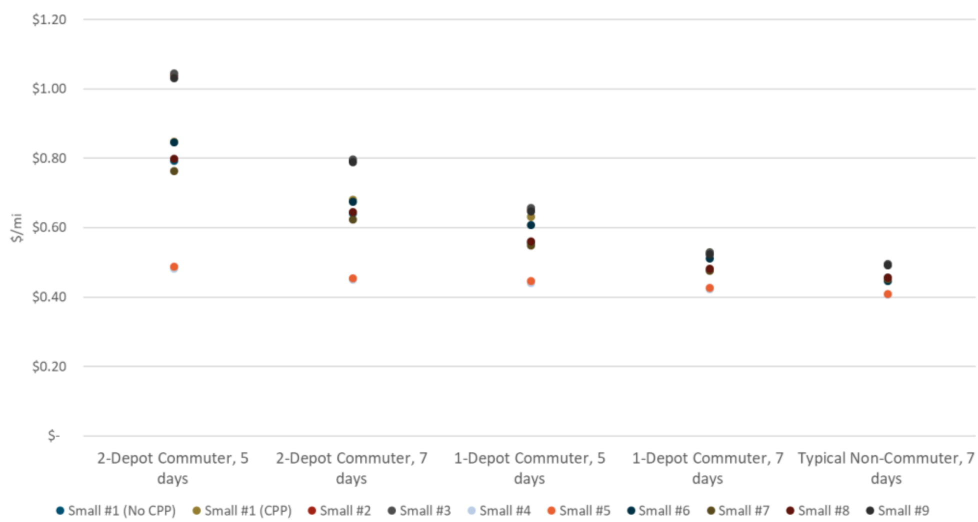


Figure 2 below displays the results on a dollar per mile basis. Results range from under $0.50 per mile to over $1.00 per mile. As described in Section 3C, changing our results from $ per kWh to $ per mile involves scaling by the 2.22 kWh per mile value, and therefore our rate structure recommendation does not change.

Figure 2: $ per hub mile results for e-bus with 500 kWh battery, 60 kW EVSE, by rate design, assuming un-managed charging



4.1.1 SMART DEPOT-CHARGING BUSES

Figure 3 below displays the average annual bill ($/kWh) for a 500 kWh e-bus with a 60 kW EVSE under Smart charging. As is evident in the figure, Smart charging results in a much narrower spread of average annual bills across rate designs.

Figure 3: $/kWh bill for e-bus with 500 kWh battery, 60 kW EVSE, by rate design, assuming Smart charging

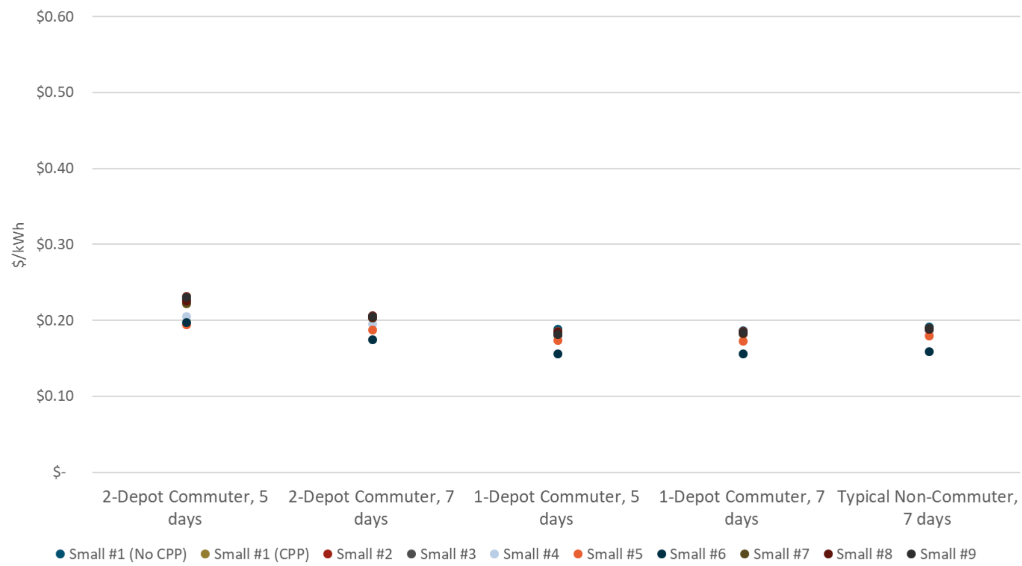
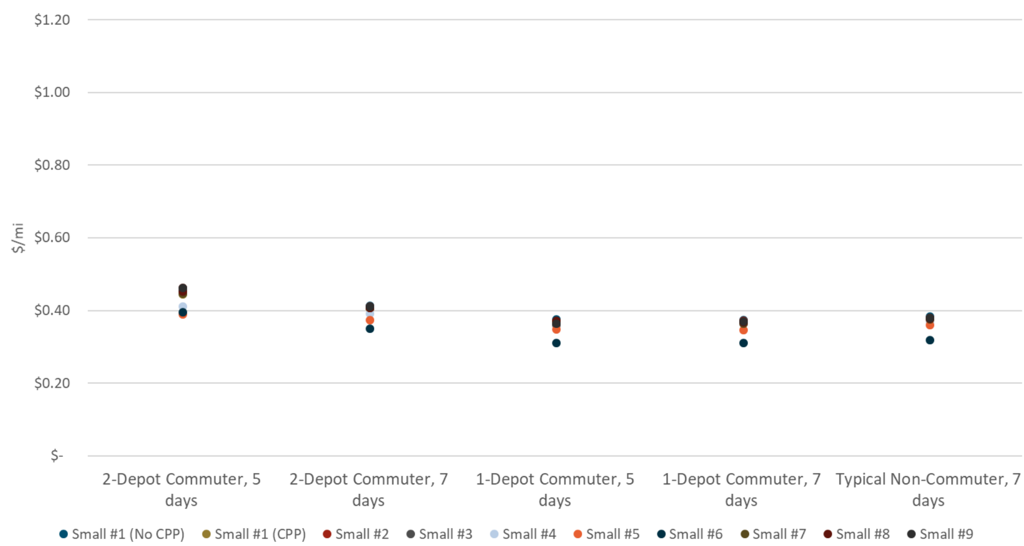


Figure 4 below shows the results on a dollar per mile basis. Results are all under $0.50 per mile.

Figure 4: $ per hub mile bill for e-bus with 500 kWh battery, 60 kW EVSE, by rate design, assuming Smart charging



Further, Smart charging leads to a substantial reduction in $/kWh cost across the board by enabling the e-bus to charge in the most economic non-driving hours. In 4 of the 5 cases, Small customer rate design #6 is the most economic. In the fifth case, Small #5 is narrowly more economic than Small #6. Small #6 has maximum monthly demand charges per the default rate structure, but higher energy rates in the summer on-peak and winter mid-peak periods, and low energy rates outside of these periods. Smart charging can avoid high demand charges and on/mid-peak periods in this rate structure and enable the e-bus to charge in hours when energy costs are lowest. Small #5 collects generation, transmission and distribution costs via energy rates with default TOU ratios but has no maximum monthly demand charges.

Combining the un-managed and Smart charging results suggests that for today's depot-charging e-bus technology:

1) Smart charging provides bill savings versus un-managed charging.

2) The lowest bills for today's depot-charging bus and EVSE technologies are those that *combine* a) a rate that features a demand charge and includes significant differences in energy rates between on-peak and off-peak periods *with* b) Smart charging technology that can avoid high demand charges and take advantage of low off-peak prices.

3) If Smart charging is *not* reliably available, or costs more than the total bill savings available, then a rate *without* a demand charge (like Small #4) will lead to the lowest bills.

Figure 5 and Figure 6 provide examples of these conclusions, showing the most economic rate structures for today's e-bus technology for un-managed and Smart charging. The two figures show 2 different Bus types: a typical non-commuter bus operating 7 days per week, and a 2-depot commuter bus operating 5 days/week.

Figure 5: Annual bill, Typical Non-Commuter Bus operating 7 days per week with 500 kWh battery, 60 kW EVSE, under optimal rate designs

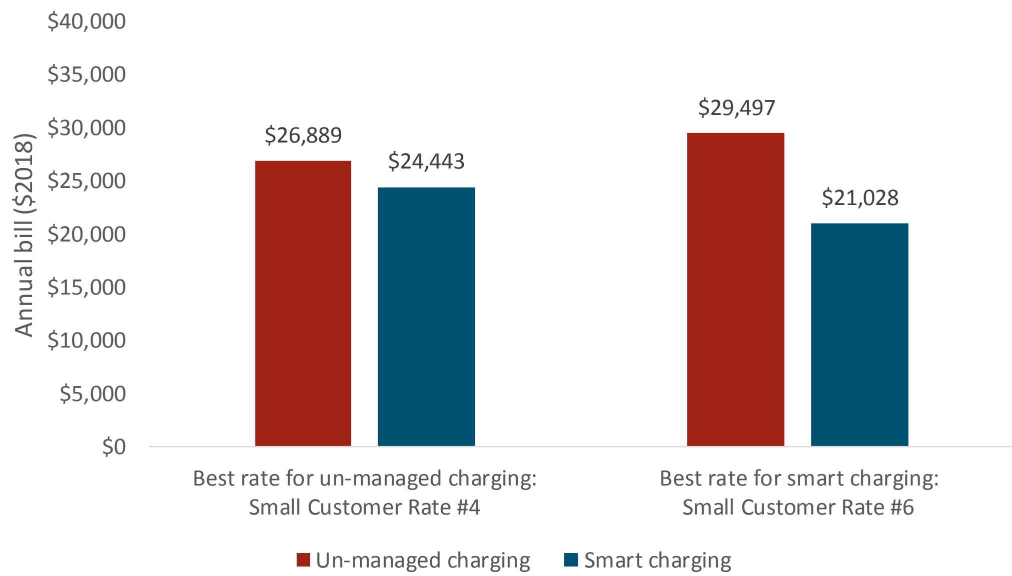
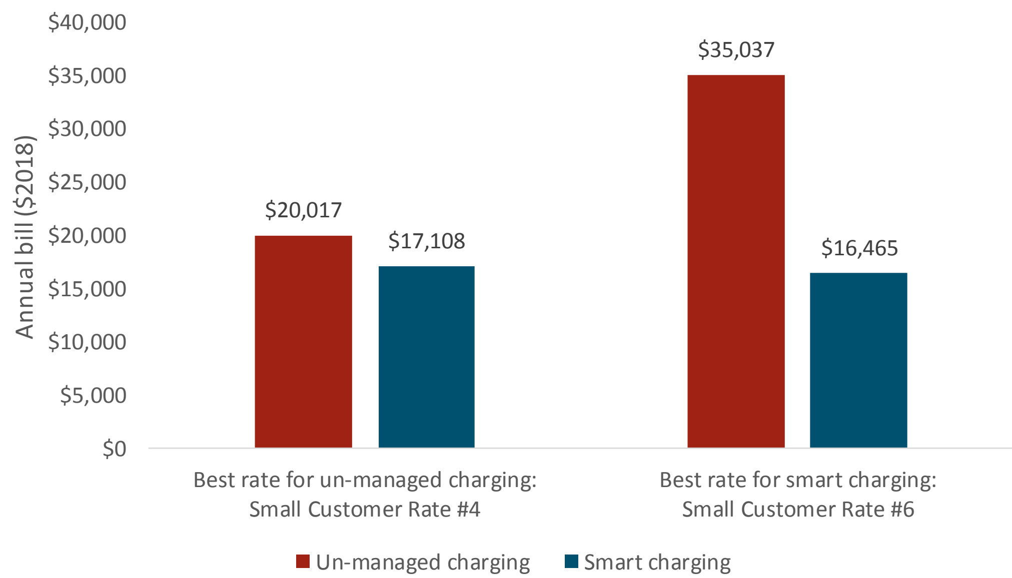


Figure 6: Annual bill, 2-Depot Commuter Bus operating 5 days per week with 500 kWh battery, 60 kW EVSE, under optimal rate designs



Results for the remainder of the Bus Types are shown in Tables 6 and 7. Under Small #4, the rate design that is preferable for un-managed charging, there is a 9% to 16% bill reduction if Smart charging is implemented. Under Small #6, there is a 29% to 53% bill reduction under smart charging.

Table 6: Value of Smart charging under the Small #4 rate structure (optimal rate for un-managed charging), 1 e-bus with 500 kWh battery and 60 kW EVSE

Bus Type	Annual Bill Unmanaged	Annual Bill, Smart	Value of Smart Charging	Smart Charging Savings (%)
2-Depot Commuter, 5 days	$20,017	$17,108	$2,909	14.5%
2-Depot Commuter, 7 days	$27,187	$23,670	$3,517	12.9%
1-Depot Commuter, 5 days	$18,337	$15,428	$2,909	15.9%
1-Depot Commuter, 7 days	$25,507	$21,990	$3,517	13.8%
Typical Non-Commuter, 7 days	$26,889	$24,443	$2,446	9.1%

Note that under this rate design with no demand charge, the commuter buses show equal savings whether they have access to 1 or 2 depots: the increase in total annual bill for the 2-depot buses is due to the additional customer charge incurred at the second depot.

Table 7: Value of Smart charging under Small Customer Rate Design #6 (optimal rate for Smart charging), 1 e-bus with 500 kWh battery and 60kW EVSE

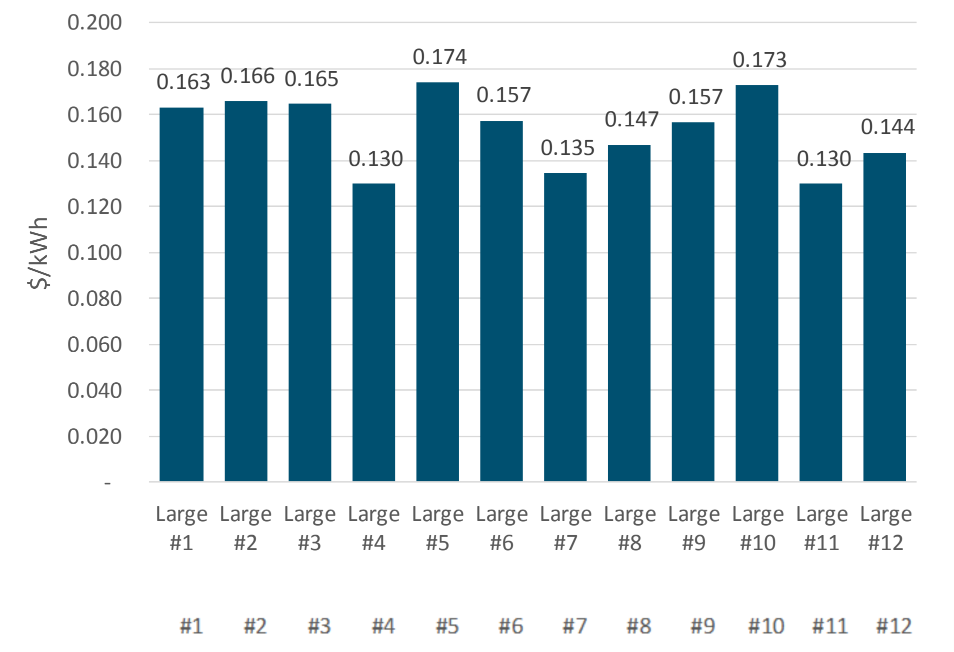
Bus Type	Annual Bill Unmanaged	Annual Bill Smart	Value of Smart Charging	Smart Charging Savings (%)
2-Depot Commuter, 5 days	$35,037	$16,465	$18,572	53.0%
2-Depot Commuter, 7 days	$40,648	$21,170	$19,478	47.9%
1-Depot Commuter, 5 days	$25,271	$13,013	$12,258	48.5%
1-Depot Commuter, 7 days	$30,882	$18,890	$11,992	38.8%
Typical Non-Commuter, 7 days	$29,497	$21,028	$8,469	28.7%

Under this design, we do see a difference in the savings available from managed charging between the 1-depot and 2-depot commuter buses: Smart charging allows buses on this rate to minimize the impact of a second demand charge.

4.1.2 ON-ROUTE CHARGING BUSES

Figure 7 below provides results for the static on-route load profile scenario. Recall that on-route charging was analyzed using the large customer rates. Figure 7 shows that the Large #4 design is the most economic rate observed. The inflexible on-route charging profile has high maximum monthly demand, often incurred in the late afternoon or early evening. The Large #4 rate design does not include a demand charge, and so avoids significant bill impacts from this peaky demand. On the other hand, the Large #5 and Large #10 designs feature the most costly demand charges, and, as expected, show the highest cost for on-route charging.

Figure 7: $/kWh bill for on-route charging bus, by rate design



We assume that the logistics of on-route charging do not enable the flexibility needed to implement Smart charging measures or technologies. To the extent that on-route charging buses are also being charged overnight at a depot or sitting at a single on-route EVSE for an extended period, the results from Smart charging will be similar to the Smart charging results presented for depot-charging buses.

B. Which Rate Structure is Best for *Tomorrow's* Depot-charging E-Buses Under Unmanaged and Smart Charging?

Results presented in this section again assume a single bus on a single EVSE.

4.1.3 TOMORROW'S DEPOT-CHARGING BUSES: UN-MANAGED CHARGING

In addition to analyzing the bill impacts of today's electric bus technology, we also delved into what impact future technology may have on rate structure recommendations. To do so:

1. The energy storage capability for each bus was increased to 1,000 kWh (an effective capacity of 700 kWh after an assumed 30% minimum SOC); and

2. EVSE charging capacity was increased from 60 kW to 500 kW.

The impact of these assumptions is discussed below. Because the available EVSE capacity is assumed to be 500 kW, we examine rate structures applicable to large customers.

The results are summarized in Figure 8 below. The major difference observed between these results and the bills we saw with today's bus technology is a dramatic increase in the upper average rate bound of these results: whereas none of the designs with "today's buses" exceeded $0.60 per kWh, more than half of the designs with "tomorrow's buses" do – in some cases exceeding $1 per kWh. This is because a 500 kW of EVSE capacity, when left un-managed, has the potential to incur a dramatically higher demand charge than 60 kW.

Under un-managed charging, Large #4 design is the most economic for 5 of the 6 Charging Profiles. The exception is the high-miles Bus Type, for which Large #11 is narrowly more economic than Large #4. Similar to the results we saw previously, this result is due to the fact these two rates do not have demand charges. Large #7, the only other rate alternative without a demand charge among those we examined, was the third most economic rate across all of these Charging Profiles. Once again, a fully flat rate structure would yield the most economic results for un-managed charging: the corresponding flat rate would be $0.121 per kWh, which is lower than all of the alternate rate structures results.

Figure 8: $/kWh bill for e-bus with 1,000 kWh battery, 500 kW EVSE, by rate design, assuming un-managed charging

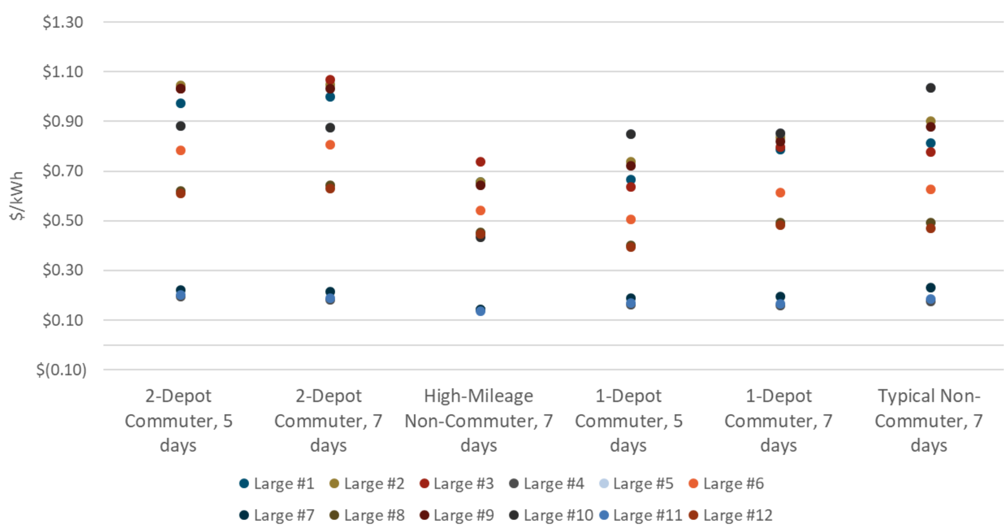
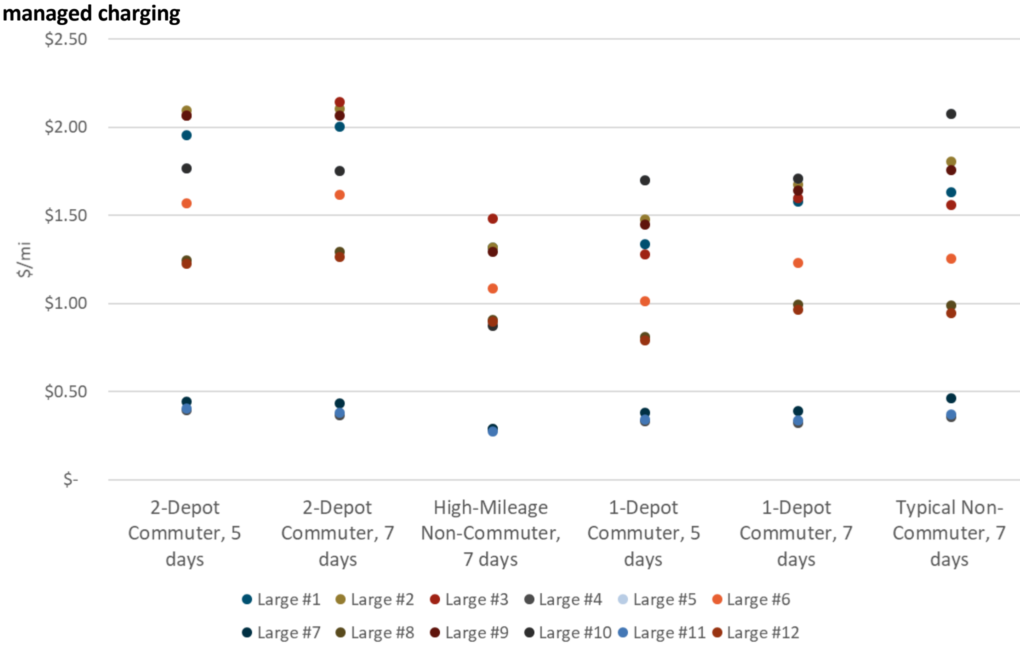


Figure 9 below shows the results on a dollar per mile basis. Results range from under $0.50 per mile to over $2.00 per mile. Again, as described in Section 3C, changing our results from $ per kWh to $ per mile involves scaling by the 2.22 kWh per mile value, and therefore our rate structure recommendation does not change.

Figure 9: $ per hub mile bill for e-bus with 1,000 kWh battery, 500 kW EVSE, by rate design, assuming un-managed charging



4.1.4 TOMORROW'S DEPOT-CHARGING BUSES: SMART CHARGING

The impact of Smart charging on bills for the depot-charging buses of 'tomorrow' is shown in Figure 10 below.

Figure 10: $/kWh bill for e-bus with 1,000 kWh battery, 500 kW EVSE, by rate design, assuming Smart charging

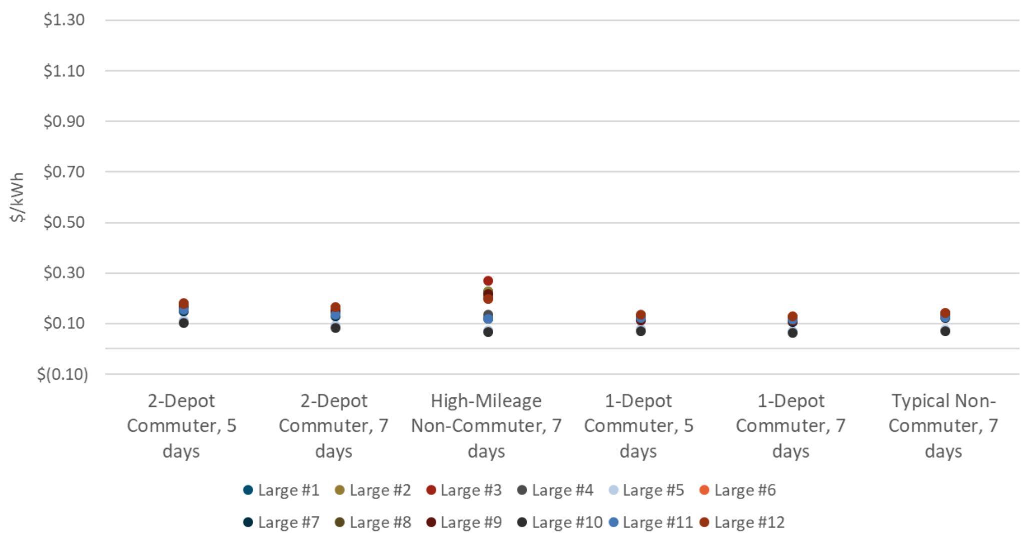
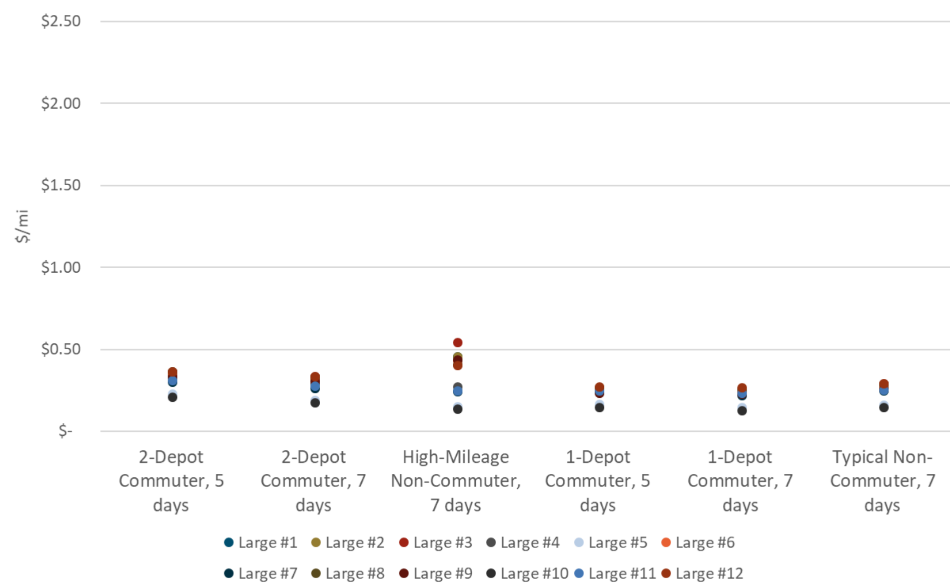


Figure 11 below shows the results on a dollar per mile basis, using the 2.22 kWh per mile assumption detailed in Section 3C. Nearly all of these results are under $0.50 per mile.

Figure 11: $ per hub mile bill for e-bus with 1,000 kWh battery, 500 kW EVSE, by rate design, assuming Smart charging



Similar to the previous results, we see a dramatic decrease in cost from smart charging compared to the un-managed case. In fact, we see a higher value of Smart charging for these higher-powered buses and EVSEs. This is because a 500 kW EVSE creates higher bills than a 60 kW EVSE when the charging is unmanaged and there is a demand charge, and because a larger battery and more charging capacity provide increased flexibility to lower bills.

For these future bus and EVSE technologies, the Large #10 rate structure is most economic. This is the result of several factors. First, this rate has time-differentiated demand charges, which are demand charges that apply only in specific hours of the day, rather than across the entire month. With the increased flexibility from the higher-capacity battery and the higher-capacity EVSE, the buses modeled can avoid charging in the Summer Peak and Winter Mid-Peak periods and therefore avoid incurring a demand charge altogether. Furthermore, because the volumetric component of Large #10 is tied to real-time prices, there is higher volatility in the hourly energy price, which further improves the economics of smart charging because the lowest-cost hours are notably lower cost than the off-peak hours under a more traditional TOU structure.

Combining the un-managed and Smart charging results suggests that tomorrow's depot-charging e-bus technology:

1) Under unmanaged charging will see higher bills than for the today's technology if the rate design includes a demand charge, as a 500 kW EVSE capacity could result in significant demand spikes.

2) Smart charging provides significant savings versus un-managed charging. The potential savings are larger than those available with today's battery and EVSE capacities due to the increased flexibility afforded by the higher battery and EVSE capacities.

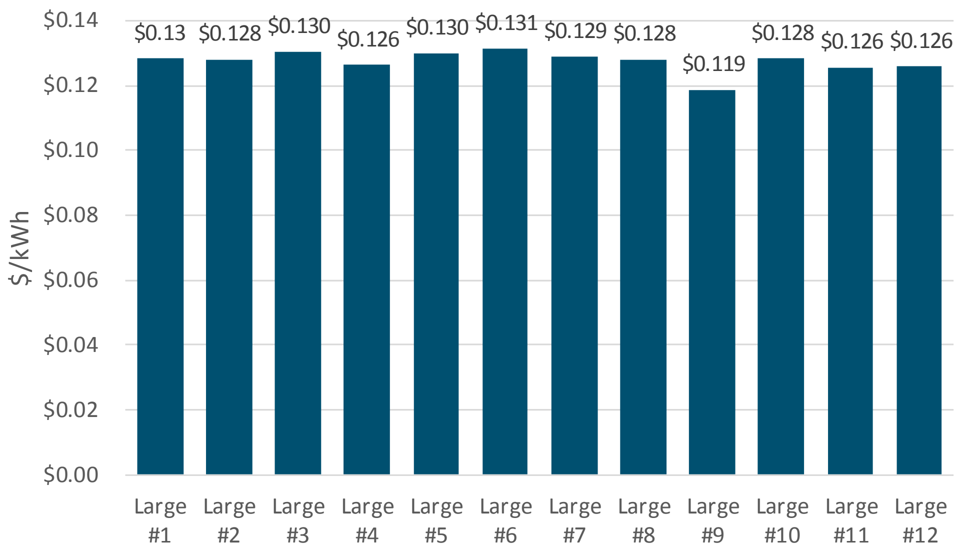
3) The lowest bills for these higher-capacity depot-charging buses and EVSE technologies are those that *combine* a) a rate featuring a demand charge and dynamic energy prices, with b) charging technology that can avoid high demand charges and take advantage of dynamic pricing volatility.

4) If Smart charging is *not* reliably available, or costs more than the total bill savings available, then a rate *without* a demand charge (like Large #4) will lead to the lowest bills.

4.1.5 ELECTRIC RAIL

Similar to on-route charging, the 2017 static electrified rail profile was assessed across the 12 large customer rate designs. The results are summarized in Figure 12 below.

Figure 12: Summary of Retail Rate Results for Electrified Rail ($/kWh)



The first observation is that the variance across the different rate structures is minimal. The difference between the most economic and least economic rates is less than $0.015/kWh. The most economic rate is Large #9. This is due to Large #9's having real-time pricing and the highest demand charges. The high load factor observed in the electrified rail's load profile reduces the demand charge impact. In particular, a large amount of the electrified rail's load is incurred mid-day in the spring, which is when Large #9 features spring super-off-peak pricing. The rail's average load, by month of the year and hour of the day, and Large #9's average price in $/kWh, are shown in Figure 13 below.

Figure 13: Average electrified rail load compared to Large #9 RTP energy rate

Average Load (kW)

	1	2	3	4	5	6	7	8	9	10	11	12
0	967	987	1031	928	939	912	845	816	1042	905	913	1138
1	795	819	849	748	735	736	688	666	880	744	750	962
2	722	731	757	682	667	675	630	653	867	782	709	855
3	786	707	719	660	610	813	765	759	1071	993	761	818
4	1086	1032	1054	1002	919	1020	943	911	1236	1131	1014	1158
5	1649	1623	1704	1635	1530	1506	1395	1376	1633	1572	1510	1711
6	1758	1756	1935	1835	1695	1620	1520	1545	1763	1698	1671	1855
7	1977	1986	2154	1986	1862	1791	1737	1749	1979	1881	1872	2050
8	1894	1868	1977	1828	1828	1766	1741	1726	1881	1744	1774	1872
9	1774	1733	1847	1794	1833	1819	1832	1808	1903	1770	1714	1759
10	1691	1651	1775	1778	1865	1820	1835	1813	1911	1776	1660	1631
11	1614	1617	1818	1821	1893	1796	1786	1764	1924	1817	1740	1599
12	1597	1630	1889	1848	1905	1827	1819	1779	1922	1846	1772	1632
13	1585	1630	1867	1872	1939	1889	1866	1832	1959	1875	1786	1660
14	1625	1655	1900	1893	1966	1907	1878	1858	1975	1911	1762	1631
15	1669	1691	1941	1931	1993	1912	1884	1857	2003	1926	1752	1610
16	1696	1696	1934	1939	2005	1894	1881	1885	2005	1970	1721	1625
17	1845	1820	2016	2047	2134	2035	2011	1995	2124	2059	1819	1771
18	1784	1768	1857	1862	2030	1946	1918	1918	2010	1909	1662	1721
19	1779	1731	1751	1686	1845	1860	1896	1882	1919	1765	1590	1727
20	1675	1632	1658	1501	1589	1603	1707	1654	1725	1562	1461	1634
21	1390	1364	1382	1239	1287	1271	1318	1239	1411	1217	1229	1399
22	1249	1250	1299	1135	1143	1150	1150	1081	1272	1080	1154	1317
23	1189	1231	1230	1088	1117	1099	1044	1017	1202	1043	1055	1299

Average Energy Rate ($/kWh)

	1	2	3	4	5	6	7	8	9	10	11	12
0	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
1	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
2	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.05	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
3	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
4	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.06
5	$ 0.06	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.07	$ 0.07
6	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.08	$ 0.08
7	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.02	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.08
8	$ 0.07	$ 0.07	$ 0.06	$ 0.02	$ 0.02	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07
9	$ 0.06	$ 0.06	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
10	$ 0.06	$ 0.06	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
11	$ 0.06	$ 0.06	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.06	$ 0.07	$ 0.06	$ 0.07	$ 0.06	$ 0.06
12	$ 0.06	$ 0.06	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.06
13	$ 0.06	$ 0.06	$ 0.02	$ 0.03	$ 0.02	$ 0.03	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.06
14	$ 0.06	$ 0.06	$ 0.02	$ 0.03	$ 0.02	$ 0.03	$ 0.07	$ 0.07	$ 0.08	$ 0.07	$ 0.06	$ 0.06
15	$ 0.06	$ 0.06	$ 0.06	$ 0.03	$ 0.02	$ 0.07	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.06	$ 0.06
16	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.03	$ 0.08	$ 0.08	$ 0.08	$ 0.09	$ 0.08	$ 0.07	$ 0.07
17	$ 0.08	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.09	$ 0.09	$ 0.08	$ 0.09	$ 0.09	$ 0.08	$ 0.08
18	$ 0.08	$ 0.08	$ 0.08	$ 0.07	$ 0.07	$ 0.09	$ 0.08	$ 0.08	$ 0.09	$ 0.08	$ 0.08	$ 0.08
19	$ 0.07	$ 0.07	$ 0.07	$ 0.08	$ 0.07	$ 0.09	$ 0.08	$ 0.08	$ 0.08	$ 0.07	$ 0.07	$ 0.07
20	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.08	$ 0.08	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07
21	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07
22	$ 0.07	$ 0.07	$ 0.06	$ 0.07	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.07
23	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07

C. What is the Relative Impact of Larger Battery Capacity versus Larger EVSE Capacity on the Value of Smart Charging?

Recall that the increased battery and charging capacity of the "future" buses create significant Smart charging flexibility and therefore significant potential bill savings. Even with *ten* 1,000 kWh Typical non-commuter, 1-depot commuter or 2-depot commuter buses operating on 500 kW of EVSE capacity, there was still enough flexibility to use Smart charging technologies to avoid incurring the time-differentiated demand charges of the optimal Large #10 rate structure, *and* to take advantage of its real-time pricing energy charges.

Sensitivity analysis suggests that the vast majority of this value comes from the higher EVSE charging capacity rather than the larger bus battery capacity.

Table 8 shows the annual bill reduction value of 500 kWh of e-bus battery capacity under smart charging. Note that the values in Table 8 are *annual* values, meaning that each year, spanning the lifetime of the electrified bus fleet, this value can be realized. Assuming a 12-year lifetime for each bus and a 7% discount rate, this implies a lifetime present value of between $529 (2-Depot, 5 day bus, 1 bus per EVSE) and $9,550 (2- and 1-Depot, 5 day bus, 10 buses per EVSE) of buying an additional 500 kWh of storage capacity for each bus at a given facility. On a per kWh of additional storage basis, though, we see the value ranging from only $0.32/kWh (Typical Non-commuter, 7 days, 10 buses per EVSE) to $4.65/kWh (2- and 1-Depot, 7 days, 1 bus per EVSE), likely well below the current cost of attaining an additional kWh of storage. [9]

This reveals that even in the higher utilization cases, the value of additional bus battery capacity is minimal. Thus, while larger bus batteries present clear benefits, such as enabling longer routes to be electrified, their value is not predominantly economic.

Table 8: Annual bill reduction value of an additional 500 kWh of e-bus battery capacity, assuming Smart charging (under Large #10)

Bus Type	1 Bus per 500 kW EVSE Power	3 Buses per 500 kW EVSE Power	10 Buses per 500 kW EVSE Power
2-Depot Commuter, 5 days	$67	$143	$1,202
2-Depot Commuter, 7 days	$293	$793	$453
1-Depot Commuter, 5 days	$67	$143	$1,202
1-Depot Commuter, 7 days	$293	$793	$453
Typical Non-Commuter, 7 days	$111	$225	$204

* Note that the high mileage bus is not shown here, as our modeling showed that it was not possible to electrify this bus type with a 500 kWh battery (assuming a 30% minimum state of charge)

[9] The increase in the value of additional storage for the buses that run 5 days per week as they move from 3 buses to 10 buses may at first seem counterintuitive. This result occurs because squeezing 10 buses of this type onto a given charging capacity (500 kW in this case) causes more weekday versus weekend charging, increasing bills. An extra 500 kWh of storage therefore becomes more valuable, by allowing a reduction in weekday charging. Despite this increased battery capacity value, our finding that additional charging capacity is generally more valuable than additional battery capacity suggests that agencies are likely to gain larger bill reductions by investing in charging (where economic) once they are experiencing these bill increases, rather than increasing battery capacity.

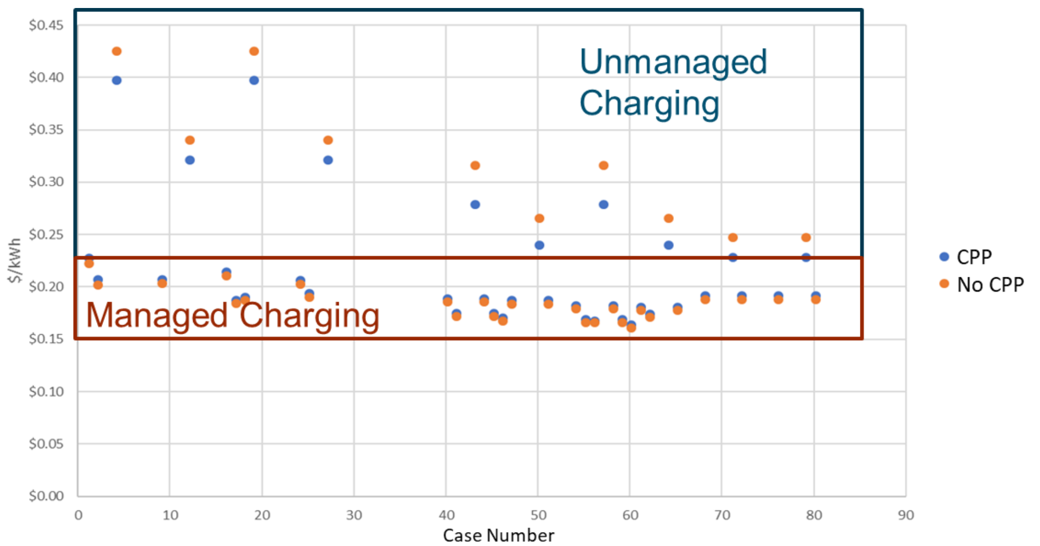
D. Does Rate Level Impact these Rate Structure Recommendations?

For both small and large customers, under unmanaged charging, the rate structures that do not include a demand charge are the most economic. Under Smart charging, for both small and large customers, designs with time-based price signals and large differentials between peak and off-peak prices yield the best economics. From these results, it is clear that rate level (i.e., the average rate for the customer class, expressed in $/kWh) does not impact the rate structure recommendations.

E. What is the Impact of the PDP/CPP Rate Structure?

A related rate structure question is whether there is sufficient charging flexibility for opting into a PDP/CPP rate to be economic. A PDP/CPP rate amounts to a few hours throughout the whole year of very high volumetric pricing, with the benefit of a reduced summer on-peak demand charge throughout all summer months. Customers with very low flexibility would be wise to avoid these rates, as they can be costly if load is incurred during a PDP/CPP event. However, if a customer is sufficiently flexible so as to avoid this handful of events, CPP/PDP rates can be cost effective. Under Smart charging, the PDP/CPP rate structure adds additional economic benefit. However, the inverse is also true: if charging is not managed, the PDP/CPP rates are not economic. This result is displayed across all cases in Figure 14 below.

Figure 14: Small #1 design with and without PDP for Smart and unmanaged charging, across all Charging Profiles.

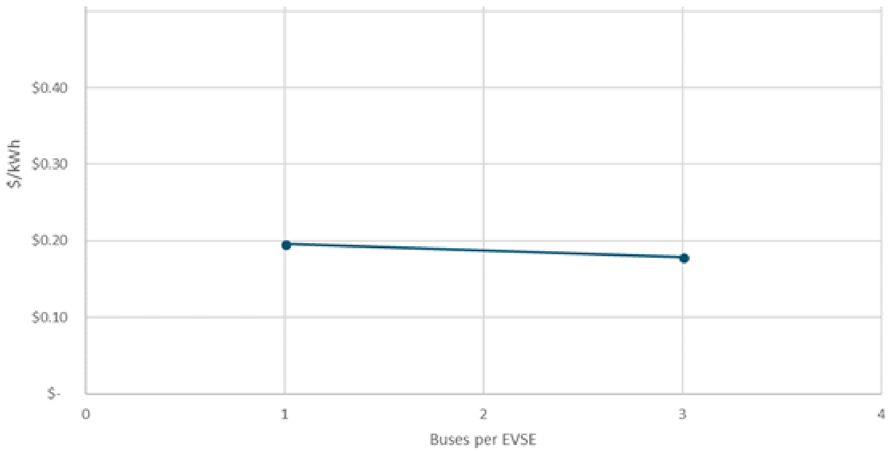


F. What is the Impact of Increased EVSE Utilization?

The impact of increased numbers of e-buses in an agency's fleet was modeled by increasing the utilization of a given EVSE for customers with smart charging. This sensitivity explored how bills are impacted if, rather than servicing just one bus, a 60 kW EVSE serviced 3 or 10 buses. Note that this exercise assumes Smart charging of electric buses, as buses would need to be sequenced to be able to share a given charging capacity. When more buses smartly share charging capacity, we see a moderate reduction in cost, in $/kWh terms. While there is a slight *increase* in the volumetric portion of the bill, as some charging must be accomplished in more expensive TOU periods, this was outweighed by the impact of the customer charge**;** because the customer charge does not scale with the number of buses per EVSE, with increased EVSE utilization the customer charge is prorated over additional load thereby *reducing* the overall $/kWh cost. An example of this impact is displayed in Figure 15 below, which shows the impact for a 2-Depot, 5-day Commuter Charging

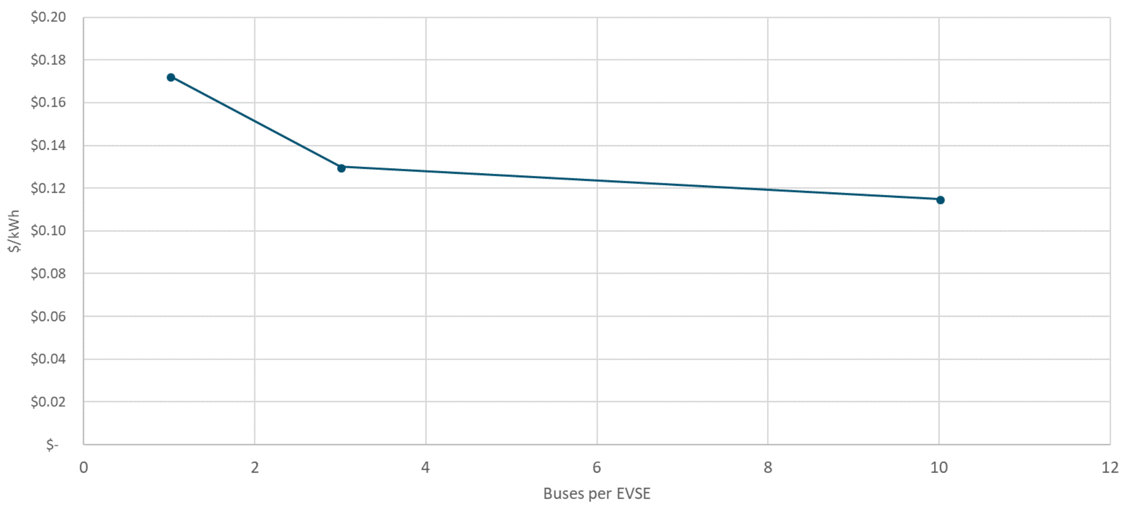
Profile under the Small #5 rate design, which was the most economic rate structure for this particular Bus Type.

Figure 15: Impact ($/kWh) of increasing from one bus per EVSE to three buses per EVSE for 2-depot 5-day commuter Charging Profile on the Small #5 design



Of note is the fact that this phenomenon persists even under scenarios with high charging capacity and rates with demand charges. One might expect that increasing the number of buses being served by a charger would force dramatically more expensive behavior from a demand charge perspective. However, as Figure 16 shows below, this is not the case. Again, the volumetric portion of the customer bill *does* increase, but because the customer charge is being spread over more buses (and thus more load), the overall $/kWh cost comes *down* with higher utilization.

Figure 16: Impact ($/kWh) of increasing from one bus per EVSE to three and ten buses per EVSE for 2-depot 5-day commuter Charging Profile on the Large #9 rate design



Importantly, though total *bills* went down as we increased utilization of charging infrastructure, the rate *structure* recommendations described previously in Sections 4a and 4b remain the same at all levels of charger utilization across the scenarios we analyzed.

G. How Constrained are the High EVSE Utilization Cases?

Today's 60 kW EVSE capacity dramatically limits the number of buses that can be supported per EVSE using Smart charging technology: in only two scenarios (commuter buses with 1,000 kWh batteries) could 4 buses could be supported by the single 60 kW EVSE. In all other instances, no more than 3, and often only 1 or 2 buses could sufficiently charge on a single 60 kW EVSE. High mileage buses cannot be supported with 60 kW of charging capacity.

On the other hand, 500 kW of charging capacity can support up to fifteen 1,000 kWh typical non-commuter, 1-depot commuter, or 2-depot commuter Charging Profiles, or three high mileage buses.

However, even when the maximum number of buses was stacked onto a single EVSE, there was still enough flexibility for highly effective Smart charging. For example, under instances with on-peak demand charges, all buses were able to avoid incurring load in this TOU period. Similarly, 2 depot buses were able to contain all demand at only one of the depots, in order to avoid incurring demand charges at both sites. This indicates that increasing the utilization of EVSEs for electrified buses is "chunky": the buses are sufficiently flexible to charge optimally until so many buses have been added that there simply isn't enough energy to go around.

H. Are There Additional Discount Mechanisms that CTA Could Pursue?

Three additional discount mechanisms could potentially be employed to achieve rate discounts for electrified transit. These are the economic development rate discount structure, conjunctive billing, and a SCE Schedule ME-style discount structure. The potential applicability of each of these mechanisms is described below.

4.1.6 ECONOMIC DEVELOPMENT RATE DISCOUNT STRUCTURE

Economic development rates (EDR) provide electric rate discounts to attract, expand or retain load of at least 200 kW that would cease operating in or relocate outside of California if a rate discount were not provided. Note EDR is a rate discount that is applied to the otherwise applicable tariff (for example, it would be applied to the Small #4 or Large #9 designs). The term of the discount is 5 years. PG&E's and SCE's discounts are generally 12% but can be as high as 30% in cities and counties where the unemployment rate is at least 25% higher than the state average. While it is unlikely that this rate discount mechanism could be applied for electrified transit generally, CTA could explore with utilities whether a similar discount structure could be implemented to accelerate penetration of e-buses in disadvantaged communities with high levels of air pollution.

4.1.7 CONJUNCTIVE BILLING

Conjunctive billing is a billing mechanism commonly employed for electrified rail – note it is not a rate design. Under conjunctive billing, quantities of billing determinants such as energy, demand and customer charges from two or more meters are combined into single quantities for the purposes of billing, as if the bill were for a single meter or service. This billing treatment better captures the demand electrified rail imposes on the system compared to a traditional billing arrangement incurring the sum of non-coincident demand measured at each traction power meter (injection point).

On-route charging closely matches the electric rail situation. Similar to an electrified train, under on-route charging, the same bus charges at different locations on a fixed route. CTA could consider working with transit agencies that perform on-route charging for e-buses to ensure that they receive conjunctive billing treatment from their electricity supplier.

4.1.8 SCHEDULE ME DISCOUNT STRUCTURE

SCE's Schedule ME is applicable to Maritime Entities at the Port of Long Beach. Schedule ME provides rate discounts and a program under which SCE installs major electric infrastructure at no cost to the port or its tenants. These cost discounts support critical electrification and environmental improvement projects at the Port in recognition of the Port's electrification program and resulting air quality improvement in the region.

CTA could explore with utilities whether a similar rate structure could be extended to electrified transit in recognition of the clean air benefits provided by electrification, the critical public service provided by public transit in serving low-income residents who are dependent on transit for access to work, medical care and other critical services, and the important role of public transit in economic development by facilitating access of workers to employers.

Calculation of the rate discount provided under this tariff is complex because it is based on a customer-specific contribution to margin (CTM) calculation, therefore it was not included in these results. It generally provides material savings to smaller customers served at low voltage levels. An additional benefit could result to the extent that agencies could take some level of service under a non-firm tariff such as SCE's Base Interruptible Program.

5 Appendix A: Modeling Smart Charging

E3's Smart charging profiles used an hourly, linear optimization program designed to produce load profiles representative of electric vehicle operators under a given tariff to minimize customer bills. The optimization model determines the hourly charging profile that minimizes customer electricity bills under the applicable electricity tariffs on a monthly basis, co-optimizing volumetric charges and demand charges when applicable. Tariff charges that are not associated with the monthly load profile of a customer (e.g. monthly fixed charges) do not change with charging behavior and thus, while included in revenue calculations, are not included in the optimization of charging profiles. For fleets controlled by a single operator, the model jointly optimizes charging of all the fleet vehicles.

The optimization model is also subject to the physical and behavioral constraints listed in Table 9. Inputs to the optimization include vehicle characteristics, driving behavior for each vehicle and corresponding eVMT, charging levels, and applicable retail tariffs. The result of the optimization is optimal hourly electricity charging demand.

Table 9: PEV Grid Impacts Model Optimization Constraints

5.1.1.1 Physical Constraints
• **SOC Limits:** The SOC for each vehicle cannot be less than 30% of the stated vehicle's battery size (kWh)
• **Charging Rate Limit:** The hourly increase in SOC for each vehicle cannot exceed the stated vehicle's maximum charging capacity (kW)
• **Charger Limit:** The sum of the demands for each vehicle in a given hour cannot exceed capacity of the charger (kW)
5.1.1.2 Behavioral Constraints *Beyond the physical constraints of a PEV battery and charger, further behavioral constraints are implemented to capture the daily driving needs of a PEV operator*
• **Availability**: PEVs may only charge when not in use and parked at a site with available charging. Each vehicle modeled has a weekday and weekend availability profile; in hours when charging is unavailable, the corresponding vehicle cannot charge
• **Driving Profile**: Each vehicle modeled has a weekday and weekend driving profile with a corresponding charging load based on required eVMT. PEVs must charge sufficiently so that they have enough stored energy to complete all scheduled drives

6 Appendix B: Rate Design Data

The rate design process generally employs a cost-based approach wherein the rate designers establish the amount of target revenue to be collected from each type of charge (e.g.: energy, demand, customer) for a customer group, and divide those revenues by the expected usage for each charge for the entire customer group. In rate design parlance, each rate component equals the revenue requirement for that component divided by the billing determinant for the component, where the revenue requirement is the revenue that the utility is allowed to collect in a given year. For example, if the revenue requirement for on-peak energy is $100,000, and the expected amount of on-peak usage is 1,000,000 kWh, the resulting on-peak energy rate would be 10 cents per kWh. The revenue requirement is allocated to each customer class via cost of service study methodologies that are grounded in California Public Utilities Commission regulatory precedent. Class billing determinants include the number of customers, annual kWh usage, and monthly maximum demand including by TOU.

Following the cost-based approach, the alternate rates in this report are the result of reassigning revenue requirements to other rate components and developing estimates of billing determinants based on publicly available customer usage characteristic data.

The revenue requirements and billing determinants data utilized to develop rate structure alternatives for small and large customers is described below.

A. Time of Use Definitions

As more solar generation is added to California’s electricity grid in the coming years, the on-peak period is expected to shift from late afternoon to early evening. Time-of-use (TOU) periods proposed by PG&E and SCE reflect this situation and these TOU periods have been utilized in this study. Table 10 below shows PG&E's TOU definitions, with on-peak periods from 4 pm to 9 pm daily. PG&E's proposed rates do not distinguish between weekdays, weekends and holidays.

Table 10: Small Customer TOU definitions

TOU Period	Season	Hours
On-Peak	Summer June - September	4 pm - 9 pm
	Winter October - May	4 pm - 9 pm
Partial Peak	Summer June - September	2 pm - 4 pm and 9 pm - 11 pm
	Winter October - May	n/a-
Off-Peak	Summer June - September	11 pm - 2 pm
	Winter October - May	9 pm - 4 pm
Super Off-Peak	Spring March - May	9 am - 2 pm

Table 11 below shows the SCE TOU definitions. SCE TOU periods distinguish between weekday and weekend/holiday usage only during the summer months.

Table 11: Large customer TOU definitions

TOU	Season	Hours
On-Peak	Summer June - September	4 pm - 9 pm Weekdays only
	Winter October - May	n/a
Partial Peak	Summer June - September	4 pm - 9pm Weekends only
	Winter October - May	4 pm - 9pm
Off-Peak	Summer June - September	9 pm - 4 pm
	Winter October - May	9 pm - 8 am
Super Off-Peak	Summer June - September	n/a
	Winter October - May	8 am - 4 pm

Note that the super off-peak period for SCE differs from PG&E's in that it is valid for the entire winter season.

B. Small Customer Rate Design Data

The small customer rate design utilizes data for the PG&E A-10 secondary voltage customer class. This class is applicable for customers with maximum demand between 200 kW and 499 kW. The majority of PG&E's A-10 customers are served at secondary voltage therefore revenue requirements and billing determinants utilize secondary voltage data.

6.1.1 BILLING DETERMINANTS

Table 12 below summarizes billing determinants utilized in the small customer rate designs. The demand billing determinants are the sum of the non-coincident maximum demand for each customer in each month of the year. The energy billing determinants are the annual kWh usage in each TOU period. The customer billing determinants are the sum of the number of customers in each month of the year.

Table 12: Small customer billing determinants[10]

Category	Season	TOU	Bundled	System
Demand (Maximum KW)	Summer	n/a	9,439,636	11,836,624
	Winter	n/a	15,602,463	19,497,870
Demand Total			**25,042,099**	**31,334,494**
Energy (kWh)	Summer	Peak	593,777,132	746,796,244
		Mid Peak	635,003,664	798,647,045
		Off Peak	1,505,716,570	1,893,746,692
	Winter	Mid Peak	1,249,164,199	1,571,079,589
		Off Peak	2,994,042,100	3,765,620,593
	Spring	*Super Off Peak*	*490,129,999*	*616,438,766*
Energy Total			**7,467,833,664**	**9,392,328,930**
Customer (months)	Summer	n/a	147,799	189,419
	Winter	n/a	286,497	366,856
Customer Total			**434,296**	**556,275**

PG&E's Motion for Adoption of the Standby and Medium and Large Light and Power Rate Design Supplemental Settlement Agreement[11] (2018 GRC Settlement) established a $.05169/kWh super off-peak (SOP) generation energy rate but did not provide publicly available billing determinants

[10] See workpapers supporting amended testimony from January 2017 in the 2017 GRC Phase 2 filing. The data is contained in the "RD_CI_GRC" Microsoft Excel workbook in the "IN_CI_Rate Inputs" tab. **https://pgera.azurewebsites.net** k

[11] Motion of Pacific Gas and Electric Company for Adoption of the Standby and Medium and Large Light and Power Rate Design Supplemental Settlement Agreement **http://docs.cpuc.ca.gov/PublishedDocs/** k

for this TOU period. E3 utilized PG&E's 2017 dynamic load profile (DLP) data for the A-10 customer class[12] to estimate SOP usage. Because 2017 A-10 DLP usage does not match PG&E 2017 GRC A-10 billing determinants, DLP usage was scaled to match GRC usage by season (summer/winter). The 2017 SOP usage estimate derived from the DLP was subtracted from the winter off-peak GRC value so that the total usage in this period is consistent with the GRC totals of 3,484,172,098 kWh for bundled customers and 4,382,059,359 kWh for system usage. Note that DLP is already adjusted for daylight savings.

6.1.2 REVENUE REQUIREMENTS

Table 13 below shows the revenue requirements data used in the rate design. Note that PG&E's 2018 GRC Settlement did not provide generation revenue requirement by TOU period. The values below were calculated using the energy rates proposed in PG&E's 2018 GRC Settlement, multiplied by the bundled energy billing determinants listed in Section 2.1.1.[13]

[12] Dynamic Load Profile available at **https://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml**

[13] See workpapers supporting amended testimony from January 2017 in the 2017 GRC Phase 2 filing. The data is contained in the "RD_CI_GRC" Microsoft Excel workbook in the "IN_CI_Rate Inputs" tab. **https://pgera.azurewebsites.net**.

Table 13: Small customer revenue requirement[14]

Category	Season	TOU	Value ($ millions)
Distribution	Summer	n/a	187.5
	Winter	n/a	212.1
Distribution Total			**399.6**
Generation	Summer	Peak	107.8
		Mid Peak	76.1
		Off Peak	131.4
	Winter	Mid Peak	154.3
		Off Peak	263.6
	Spring	*Super Off Peak*	*25.3*
Generation Total			**758.6**
Transmission Total			**224.3**
Customer Total			**77.9**
Total Revenue Requirement			**1,460.4**

For the PG&E rate class A-10 secondary, the average bundled rate is approximately 20.0 cents per kilowatt-hour including non-bypassable and other charges.

[14] The distribution revenue requirements were obtained from the Medium and Large Light and Power Rate Design (MLRD) supplemental testimony in reply to the administrative law judge's ruling from February 2018.
The generation revenue requirements were obtained from the workpapers supporting amended testimony from January 2017 in the 2017 GRC Phase 2 filing. The data is contained in the "RD_CI_GRC" Microsoft Excel workbooks in the "IN_CI Rate Inputs" tab.
The transmission revenue requirements were also obtained from the workpapers supporting amended testimony from January 2017 in the 2017 GRC Phase 2 filing. The data is contained in the "RA_Rev Alloc_GRC" Microsoft Excel workbook in the "OUT_RA_Result" tab. See Exhibit 39- Workpaper supporting Medium and Large Light and Power Rate Design supplemental testimony from February 2018 (http://docs.cpuc.ca.gov/PublishedDocs/) and Workpapers supporting amended testimony from January 2017 (https://pgera.azurewebsites.net)

6.1.3 OTHER CHARGES AND CREDITS

In addition to the revenue requirements above, customer bills are adjusted by the rates listed in Table 14 below. These include non-bypassable charges and the climate credit. Values assumed are those in the 2018 PG&E A-10 rate schedule, effective March 1, 2018. The total of these charges is approximately 2.4 cents per kWh.

Table 14: Small customer non-bypassable and other charges

Charge	Rate ($/kWh)
TRA	0.00333
PPP	0.01416
CTC	0.00100
ECRA	(0.00001)
NDC	0.00149
DWRBC	0.00549
NSGC	0.00238
Climate Credit	(0.00378)
Total	**0.02406**

6.1.4 MARGINAL COSTS

6.1.4.1 Generation Marginal Energy Costs

Data

For the small customer rate designs with time differentiated energy rates, this report used PG&E's estimates of energy marginal costs to guide the relationship of energy rate levels by TOU period. Table 15 below shows the generation marginal energy cost data and the TOU ratios used in the rate design for small customers. The TOU ratios establish the Peak, Mid peak, and Super Off-Peak energy rates in proportion to the Off-peak energy rates. For example, the Summer Peak TOU ratio of 1.85 indicates that the Summer Peak TOU energy rate will be 85% higher than the Summer Off-peak rate.

PG&E used a publicly available model and inputs to forecast 2020 market energy prices for their Generation Marginal Energy Cost (MEC) calculation. PG&E's model is calibrated to historical market heat rates based on historical hourly energy prices in the CAISO market.[15] PG&E's forecast includes the cost of incremental fuel, variable O&M, GHG compliance, startup costs, no-load fuel costs, and congestion costs.

Table 15: Generation Marginal Energy Cost (MEC) and Settlement Energy Rate (SER) for rate class A-10 Secondary[16]

Season	TOU Period	MEC ($/kWh)	MEC TOU Ratio	SER ($/kWh)	SEC TOU Ratio
Summer	Peak	$ 0.05230	1.85	$0.18156	2.08
	Mid Peak	$ 0.04014	1.42	$0.11987	1.37
	Off Peak	$ 0.02826	1.00	$0.08730	1.00
Winter	Mid Peak	$ 0.04393	1.74	$0.12351	1.40
	Off Peak	$ 0.02527	1.00	$0.08803	1.00
	Super Off Peak (SOP)		*0.59**	$0.05169	0.59

MEC values were obtained from the PG&E Marginal Cost and Revenue Allocation Settlement from October 2017 for the 2017 GRC Phase 2 filing. The data is contained on page 1 of Attachment 1.

[15] Updated and Amended Prepared Testimony, Exhibit 9, http://docs.cpuc.ca.gov/PublishedDocs/

[16] Motion for Adoption of Settlement Agreement on Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2017 General Rate Case, Page 55 http://docs.cpuc.ca.gov/PublishedDocs

Note that this document does not contain the SOP $/kWh for PG&E. E3 utilized the marginal cost ratio for the SER for the A-10 design to estimate the SOP marginal cost-based TOU ratio.

C. Large Customer Rate Design Data

The large customer rate design utilizes data for the SCE TOU-8 customer class. This class is applicable to customers with maximum monthly demand over 500 kW. Large customer transit loads are expected to be served at primary voltage (i.e., 2 kV to 50 kV) therefore revenue requirements and billing determinants utilize SCE's primary voltage customer data.

6.1.5 BILLING DETERMINANTS

Table 16 below summarizes billing determinants utilized in the large customer rate designs. The demand billing determinants are the sum of the non-coincident maximum demand for each customer in each month of the year. Maximum demand is delineated by TOU period in addition to the monthly maximum value. The energy billing determinants are the annual kWh usage in each TOU period. The customer billing determinants are the sum of the number of customers in each month of the year. Standby rates are assumed inapplicable therefore standby customer billing determinants and revenue requirements have been excluded from the large customer analysis.

Table 16: Billing determinants for large customers

Category	Season	TOU	Bundled	System
Demand (Maximum kW)	Summer	n/a	3,521,280	5,090,992
	Winter	n/a	6,688,359	9,522,924
Maximum Demand Total			**10,209,639**	**14,613,916**
Demand (Maximum kW by TOU)	Summer	Peak	3,167,093	4,583,984
		Mid Peak	n/a	n/a
		Off Peak	n/a	n/a
	Winter	Mid Peak	6,006,515	8,561,515
		Off Peak	n/a	n/a
	Spring	Super Off Peak	n/a	n/a
Time-related Demand Total			**9,173,608**	**13,145,498**
Energy (kWh)	Summer	Peak	228,544,775	341,011,712
		Mid Peak	82,264,260	122,569,135
		Off Peak	1,151,100,415	1,715,339,133
	Winter	Mid Peak	585,549,274	859,960,283
		Off Peak	1,184,703,916	1,734,686,842
		Super Off Peak	949,600,298	1,399,317,686
Energy Total			**4,181,762,939**	**6,172,884,791**
Customer (months)	Summer	n/a	n/a	n/a
	Winter	n/a	n/a	n/a
Customer Total			**6,579**	**8,771**

6.1.6 REVENUE REQUIREMENTS

Table 17 below shows the revenue requirements data used in large customer rate design.

Table 17: Revenue requirement for large customers

Category	Season	TOU	Value ($ millions)
Distribution	Summer	n/a	n/a
	Winter	n/a	n/a
Non-TOU Distribution Total			**111.8**
	Summer	Peak	39.8
		Mid Peak	4.8
		Off Peak	18.9
	Winter	Mid Peak	16.4
		Off Peak	5.2
		Super Off Peak	2.5
Time-based Distribution Total			**87.6**
Generation	Summer	n/a	63.1
	Winter	n/a	102.7
	Summer	n/a	53.5
	Winter	n/a	25.0
Generation Total			**244.4**
Transmission Total			**70.1**
Customer Total			**1.9**
Total Revenue Requirement			**515.8**

6.1.7 REAL-TIME PRICING

Four of the large customer rate designs employ real-time pricing (RTP). SCE used an in-house PLEXOS model to forecast 2021 market prices for their MEC calculation. SCE's forecast includes the cost of incremental fuel, variable O&M, GHG compliance, startup costs, no-load fuel costs, congestion costs and line losses. Because SCE did not publicly release its hourly marginal cost estimates, the following methodology to estimate hourly day-ahead energy prices was employed.

Prices are estimated for the year 2021 because this is the year that SCE used to determine its marginal costs.[17]

Average 2021 hourly day-ahead projected market prices by TOU period per SCE TOU period definitions listed in Section 1.1.1. E3 obtained day-ahead price projections for 2021 for the CAISO SP15 zone using the California Public Utilities Commission (CPUC) Avoided Cost Calculator tool.[18] This data source includes the cost of fuel and variable O&M, and GHG compliance costs, but does not include line losses. No daylight savings time adjustment is required.

1. SCE's marginal costs include a factor for losses incurred delivering energy from transmission to primary voltage. These are displayed in Table 18 below. The hourly market prices by TOU period are multiplied by these loss factors.

Table 18: Large customer loss factors – transmission to primary[19]

TOU Period	Loss Factor
Summer On-Peak	1.0659
Summer Mid-Peak	1.0638
Summer Off-Peak	1.0585
Winter Mid-Peak	1.0577
Winter Off-Peak	1.0513
Winter Super Off-Peak	1.0553

[17] Phase 2 of 2018 General Rate Case Marginal Cost and Sales Forecast Proposals, Page 30 http://www3.sce.com/
[18] CPUC 2017 Avoided Cost Calculator Model ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/ACC_Model_v1.xlsm
[19] See SCE 2018 GRC Phase II workpaper, data contained in the "MCCR" Microsoft Excel workbook, in the "MC – Gen. Energy (kWh)" tab. http://www3.sce.com/

2. Hourly market prices including loss factors calculated in Step 2 are scaled to achieve SCE marginal costs by TOU period per SCE 2018 GRC marginal cost workpapers[20]. Resulting marginal costs (MEC) by TOU period are displayed in Table 19 below.

Table 19: Generation marginal energy cost (MEC) and generation energy rate (GER) for large customers[21]

TOU Period	MEC ($/kWh)	MEC TOU Ratio	GER ($/kWh)	GER TOU Ratio
Summer On-Peak	$0.05207	1.38	$0.06445	1.70
Summer Mid-Peak	$0.04678	1.24	$0.05791	1.53
Summer Off-Peak	$0.03767	1.00	$0.03790	1.00
Winter Mid-Peak	$0.04888	1.19	$0.04918	1.19
Winter Off-Peak	$0.04107	1.00	$0.04131	1.00
Winter Super Off-Peak	$0.02612	0.64	$0.02628	0.64

The resulting scaled hourly prices, adjusted for losses, are the estimate of marginal energy cost price signals for RTP rate structures.

6.1.8 NON-BYPASSABLE CHARGES

In addition to the revenue requirements above, customers pay the charges listed in the Table 20 below. These charges are per the 2018 SCE TOU-8 Primary rate schedule, effective March 1, 2018. The average SCE rate including the charges in Table 20 is approximately 12.1 cents per kWh.

[20] See SCE 2018 GRC Phase II workpaper, calculation shown in the "MCCR" Microsoft Excel workbook, in the "MC – Gen. Energy (kWh)" tab. http://www3.sce.com/

[21] See SCE 2018 GRC Phase II workpaper, data contained in the "RevAllo and RateDesign_M" Microsoft Excel workbook, in the "Unit-MCosts" tab. http://www3.sce.com/

Table 20: Large customer non-bypassable charges

Charge	Rate ($/kWh)
TRA	-0.00175
PPP	0.00936
CTC	0.00045
PUCRF	0.00046
NDC	0.00005
DWRBC	0.00549
NSGC	0.00400
Total	**0.01806**